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PROCEEDINGS OF A TOPICAL MEETING ON SMALL SCALE GEOTHERMAL POWER PLANTS AND GEOTHERMAL POWER PLANT PROJECTS

FEBRUARY 12-13, 1986
RENO, NEVADA

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FOREWORD

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SMALL POWER PLANT OPERATING EXPERIENCE

ELECTRICAL POWER FROM MODERATE TEMPERATURE GEOTHERMAL SOURCES WITH MODULAR MINI-POWER PLANTS

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Sparks, Nevada, U.S.A.

A B S T R A C T

Organic Rankine Cycle Geothermal Plants using moderate temperatures - (85 to 150 degree C) 185 to 400 deg. F and higher - have been pioneered by ORMAT and are made in sizes of 300 to 1200 KW factory intergrated and tested modules. The skid-mounted power package module consists of heat exchangers, turbine, generator, control systems, low voltage switch-gear as well as valves, safety circuits and piping.

Two or more units can be combined for applications where the geothermal or industrial waste heat source is sufficient to permit larger power plants to be economically installed.

Experience has been acquired in operation in low enthalpy geothermal projects in Nevada, Utah, California, Oregon and Mexico. Several typical power plants rated 800 kW 3.2 MW, 7MW and 30 MW are discussed. Reference is made to practical field experience with the units in commercial power generation, and to automation in the operation of the power plants.

1. INTRODUCTION

The small modular prefabricated power plant concept has significant advantages over conventional designs. While the cost per kW may be higher, through reduced installation, site works, engineering and design work, appreciable savings can be realized. Greatly reduced operating and maintenance costs will enhance project economics.

In fuel poor countries or in countries with inefficient distribution, remote installations can operate on a cost effective basis with long unattended continuous duty maintenance intervals.

Organic Rankine Cycle (ORC) turbogenerators in modular configuration plants (ORMP) present a viable solution in low enthalpy geothermal resources.

2. THE ORGANIC RANKINE CYCLE POWER MODULE

2. General

As with conventional steam turbines the Organic Rankine Cycle Power Module (ORMP) is based on the Rankine power cycle; but unlike steam turbines it uses an organic motive fluid instead of water and operates on a subcritical cycle. The organic Rankine cycle has the advantage that at moderate and low temperatures it has higher efficiencies than the steam cycle and requires no superheating.

Modules have been built in the power range between 400 and 1200 kW, depending on the parameters of the heat source (media, temperature and flowrate). Specially tailored models to generate power below 400 kW or above 1200 kW have been built also.

2.2 System Operation

The operation of the ORMP unit is based on the organic Rankine cycle, as follows: (Fig. 1)

Organic motive fluid, selected according to the parameters of the heat source, is pumped by the feed pump into the preheater/vaporizer where it is heated and vaporized.

The high pressure vapor expands through the vapor turbine which is direct-coupled to a generator producing conditioned grid-synchronized electric power.

The low pressure exhaust vapor condenses in a water cooled, surface condenser. The condensate is pumped by the feed pump back into the preheater, thus completing the cycle.

The thermodynamic cycle is shown in a T-S diagram in Fig 2. The schematic flow chart is shown in Fig. 3.

The geothermal ORC operation corresponds to a basic geothermal binary cycle described as follows (Fig. 4):

- The geothermal fluid coming out from the well (Wg) transfers heat to a low boiling point organic fluid, causing its vaporation (V)

- The organic fluid vapor flows to the turbine (T), which in turn is connected to a generator (G).

- The organic fluid vapor is condensed (C) and recirculated in order to complete the cycle and to be re-used.

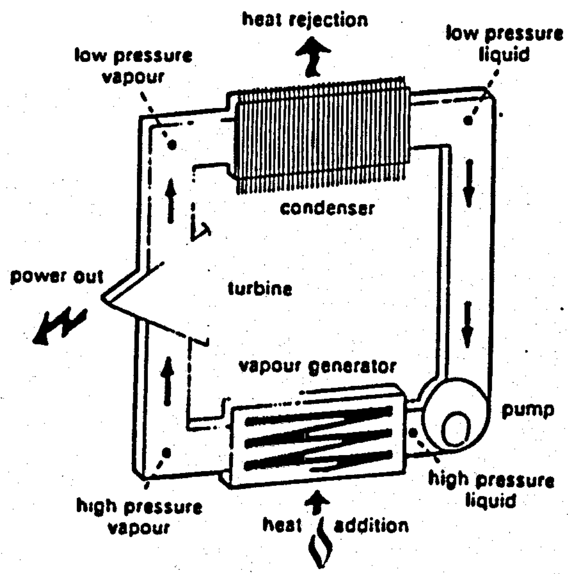

FIGURE 1: Organic Rankine Cycle

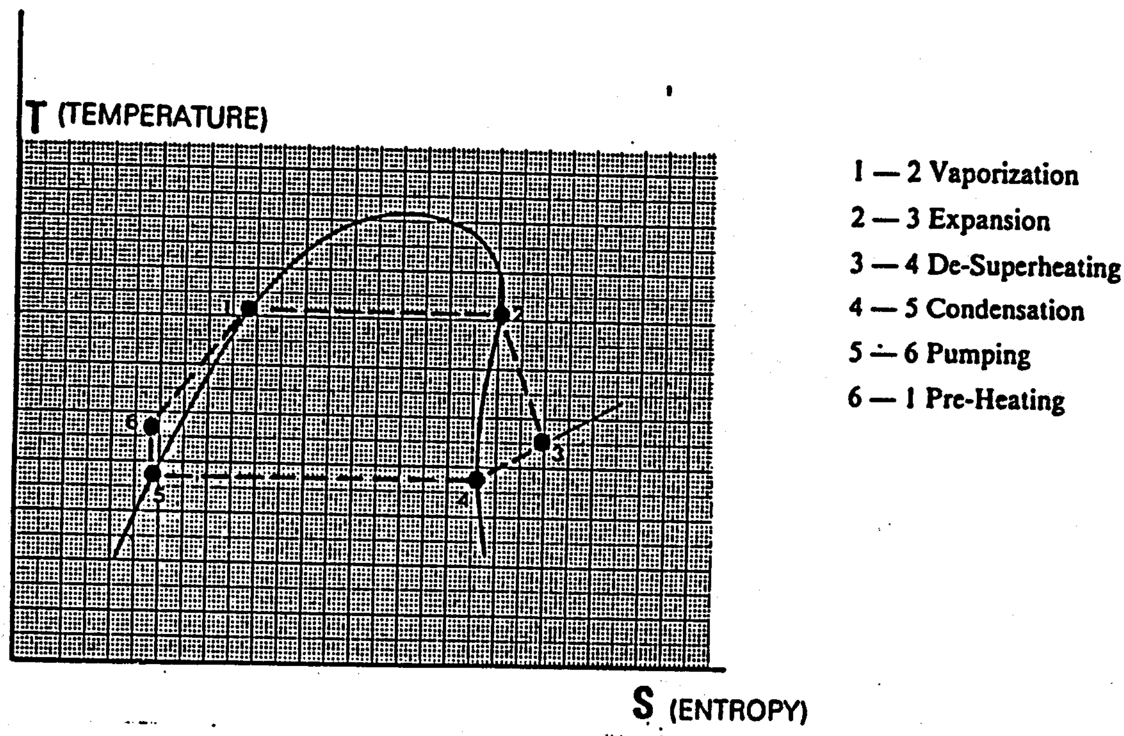

FIGURE 2: T-S Diagram of the Organic Rankine Cycle

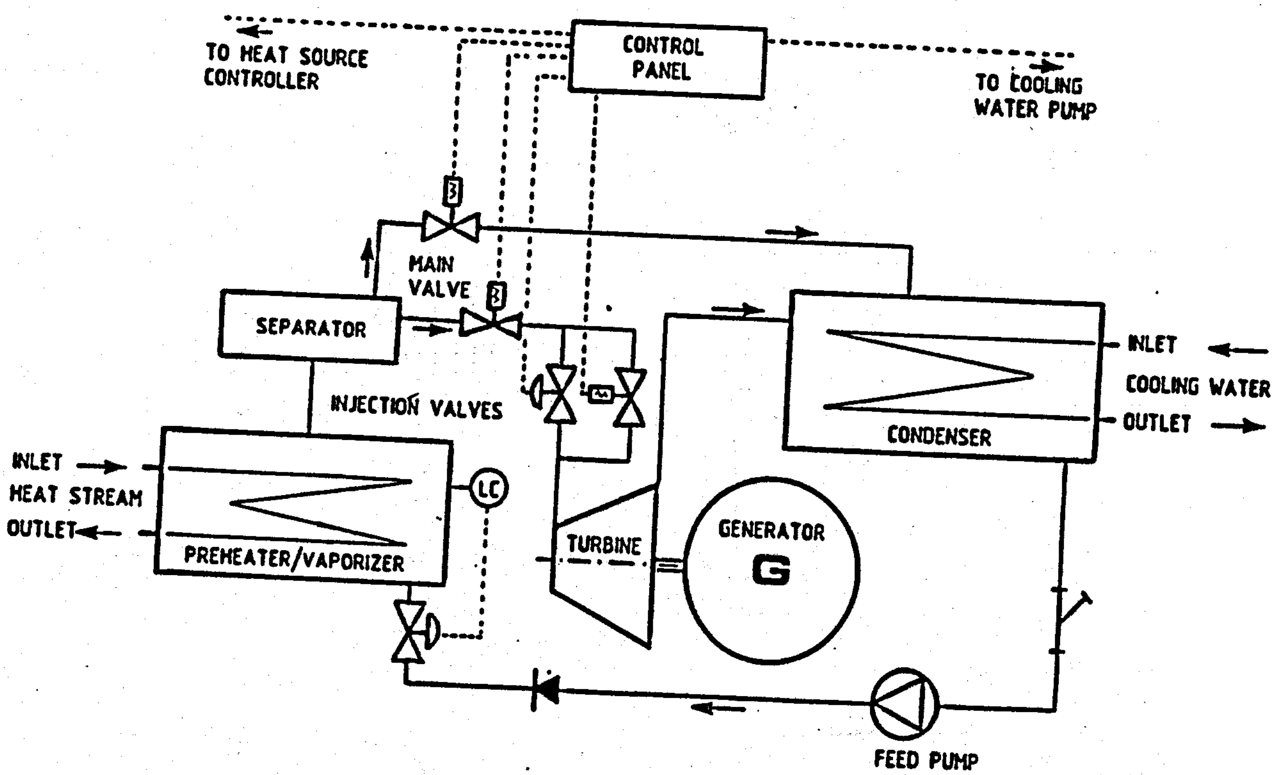

FIGURE 3: Organic Rankine Cycle Power Module (Schematic Flow Chart)

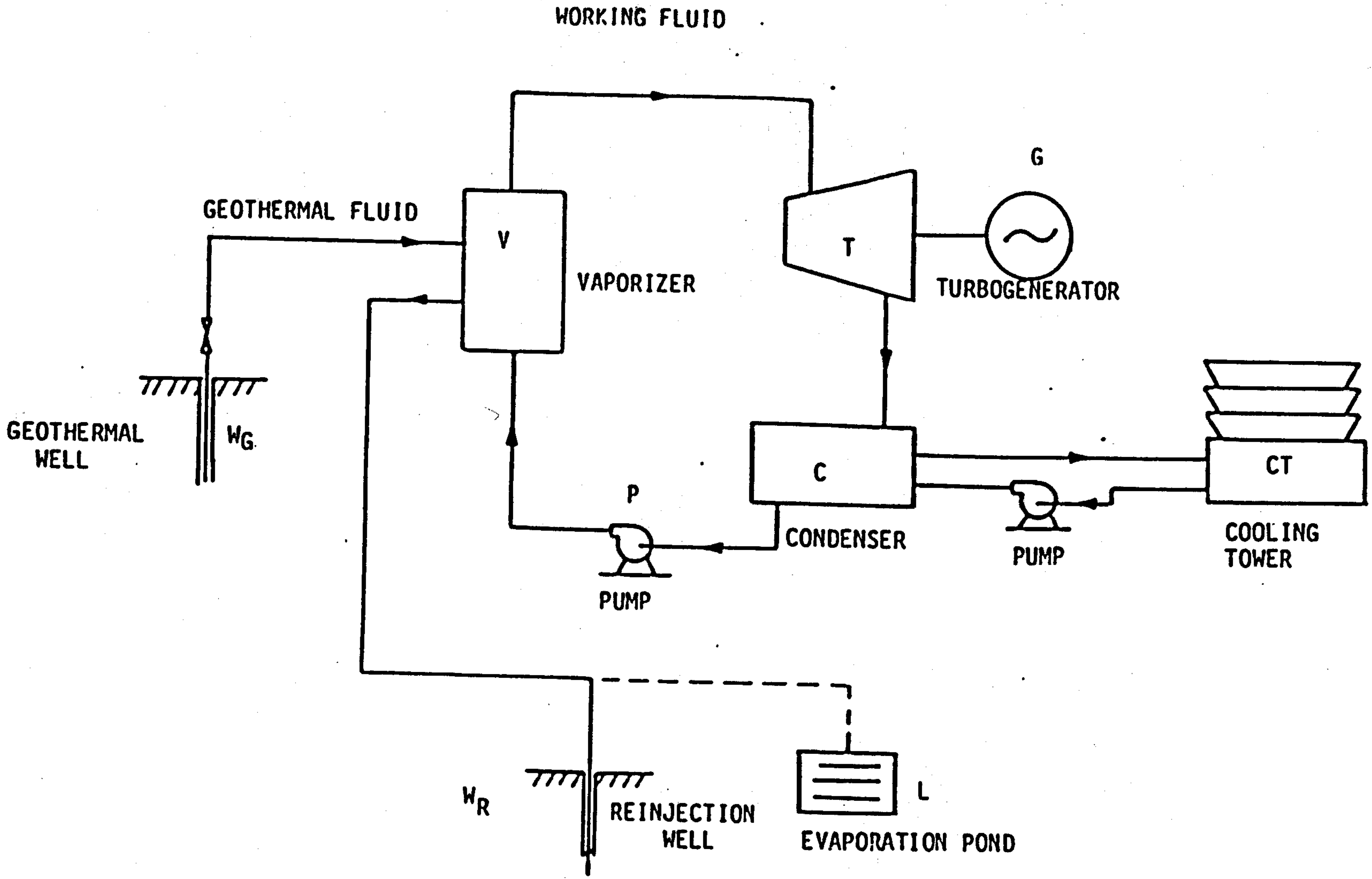

FIGURE 4 : BINARY CYCLE SYSTEM USING GEOTHERMAL FLUIDS

- The spent geothermal fluid is reinjected (Wr) or drained to an evaporation pond (L).

- The fully automated plant is installed along with a cooling tower (CT) and a circulating pump.

2.3 Installation Requirements

The self-contained factory tested ORPM's require a minimum of installation, as follows:

a. Preparation of a light, level concrete base of suitable dimensions and strength.

b. Preparation of a concrete base of suitable dimensions including a mounting flange for positioning the vertical feed pump.

c. Connecting the heat source by means of standard flanges, thermally insulated pipes and and automatic control valves.

d. Connecting the cooling water source by means of standard flanges, pipes to and from the cooling water source, a cooling water pump (if required), shut-off valves and flow switch and monitoring instruments.

e. Electrical connections with a multiple conductor wiring to wire the skid mounted junction box to the power and control cabinet and with power cables to wire the power cabinet to the generator and to the grid.

3. MODULAR GEOTHERMAL POWER PLANTS

In the past, low enthalpy liquid dominated or low pressure steam geothermal resources could not be economically used for electrical power generation because of a lack of proven equipment, and hence were abandoned.

Modular Geothermal Power Plants (MGPP) described herein were specifically designed to generate electrical power economically from low temperature liquid dominated or low pressure steam geothermal resources.

The practical applications are described below.

3.1 50 kW Geothermal ORC at Los Azufres, Mexico (Fig. 5)

This is one of the first successful applications of an ORC to a geothermal source. It was a joint demonstration project of the Instituto de Investigaciones Electricas of Mexico and Ormat.

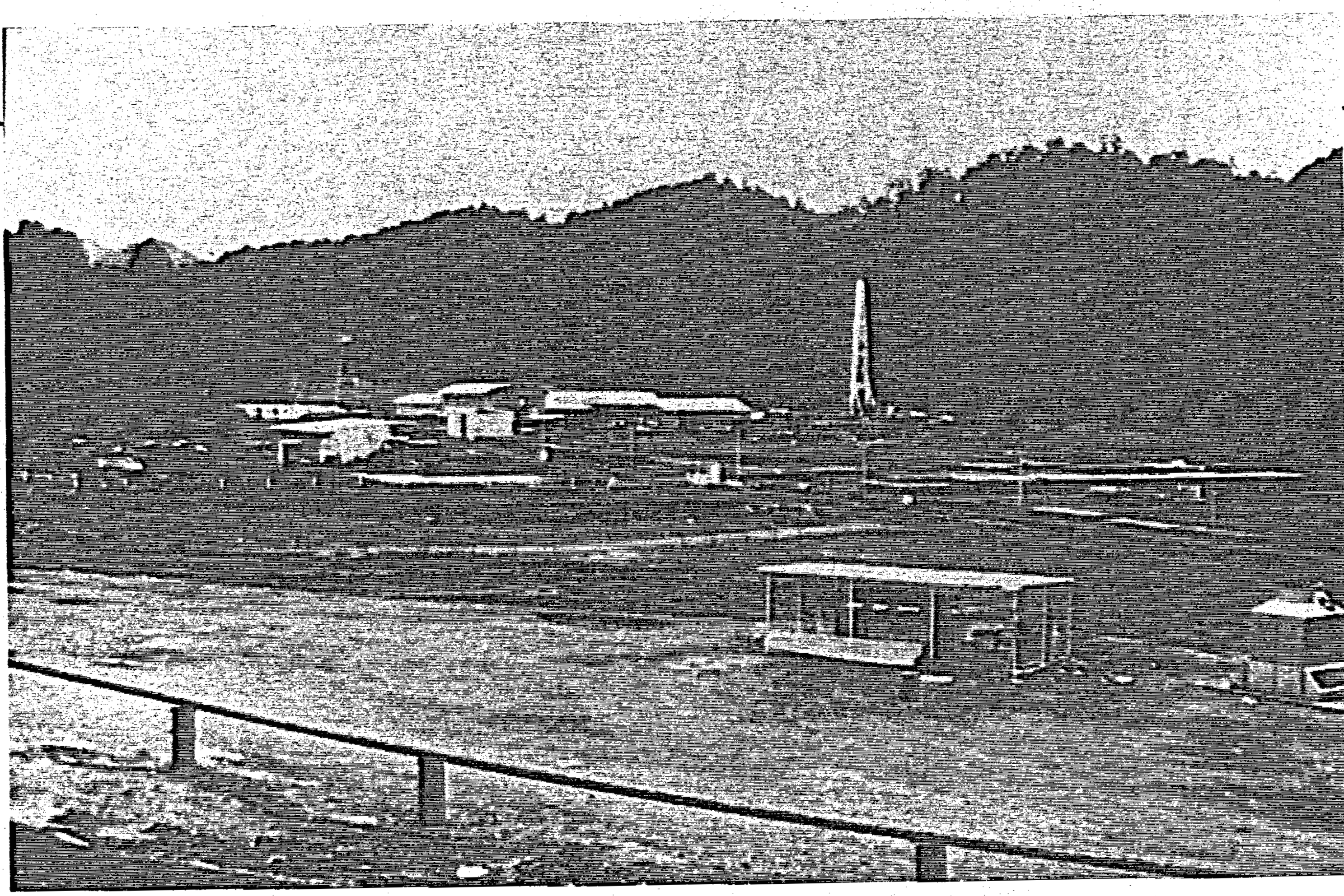

FIGURE 5 : - 50kW Geothermal ORC At Los Azufres

- The initial test period was 600 hours. Since then the unit is operated on an intermittent mode. The last series of tests was performed in 1985.

3.2 900 kW Modular Geothermal Pilot Plant in Lakeview, Oregon Fig (6).

The first pilot modular installation was made by Wood and Associates in Lakeview, Oregon. The three 300 kW unit installed ran successfully as a demonstration plant in 1982 and intermittently since then.

This was also the first experiment with a simple cascading configuration.

3.3 First Commercial Application of a Geothermal ORC: The Wabuska Plant of Tad's Enterprises (Fig. 7)

The first geothermal power plant to generate electrical power from geothermal resources in the state of Nevada was constructed by Tad's Enterprises in Wabuska. The first module, rated 800 kW, has been operating since September 1984. This OEC unit was initially designed for an industrial application and was modified at the site to use geothermal fluid as a source of power. The water at 224 degrees F from a 350 ft deep well is pumped at 765 GPM producing a gross output of 750 kW. During the initial start-up period of six months, the availability was 65%, then it increased to 70% and then to 92%. Today, it is at 96%. The unit delivers 103% of the projected output at the rated cooling water flow.

3.4 Sulphurdale, Utah (Fig 8)

The Sulphurdale project of Mother Earth Industries is a modular power plant which Ormat constructed on a turnkey basis. The first phase, using four 800 kW modules, rated at 3.2 MW, was inaugurated in September 1985. The power plant is operated by the municipal utility for the City of Provo which is also the purchaser of the power. The power is "wheeled" from Sulphurdale to Provo over Utah Power and Light transmission lines. Since startup, the four units have been operating continuously, delivering the projected output at an availability higher than 95%.

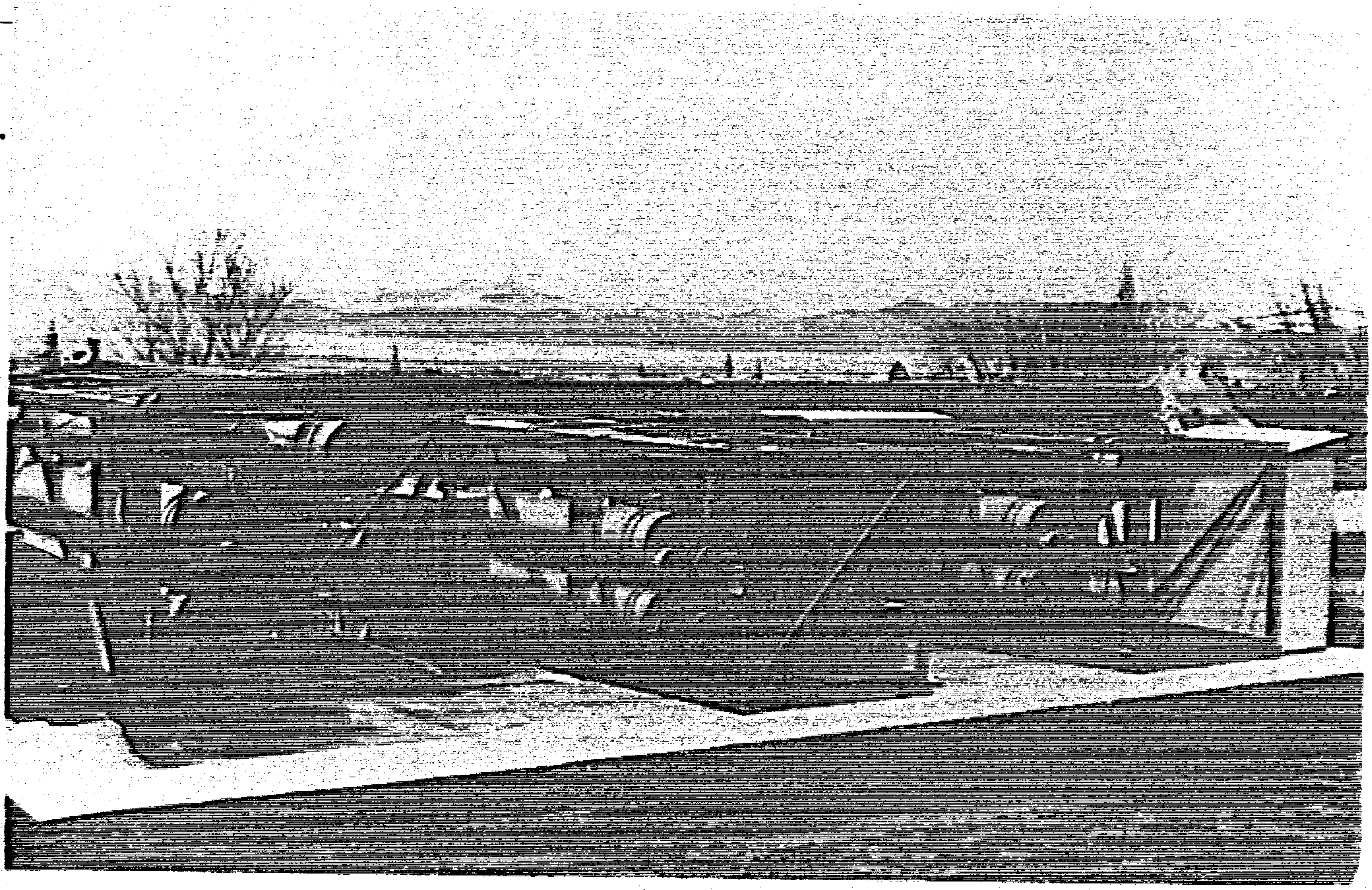

FIGURE 6 : The 900kW Modular Geothermal Plant - Lakeview

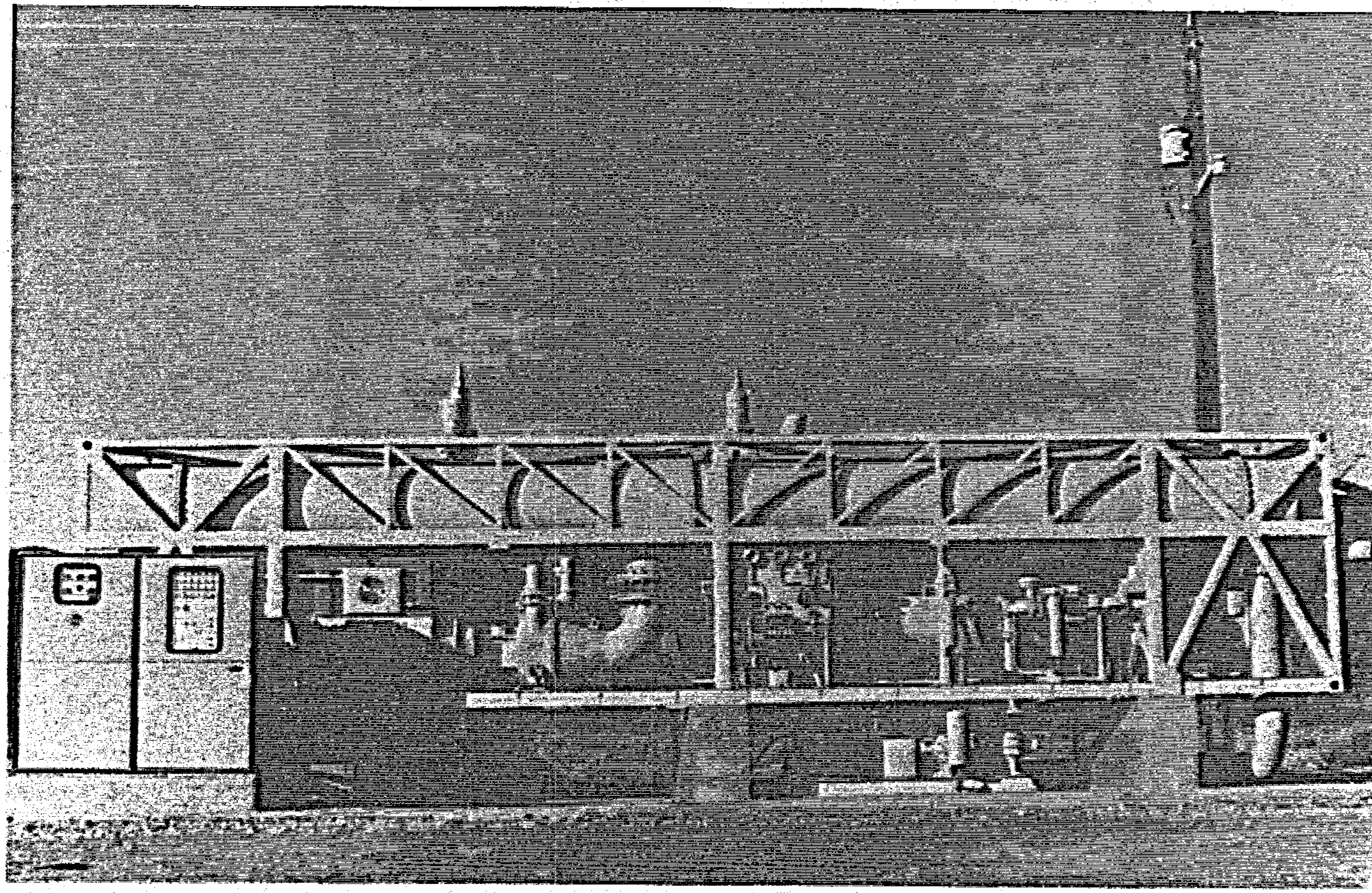

FIGURE 7 :- The 800kW Geothermal ORC - Wabuska Plant

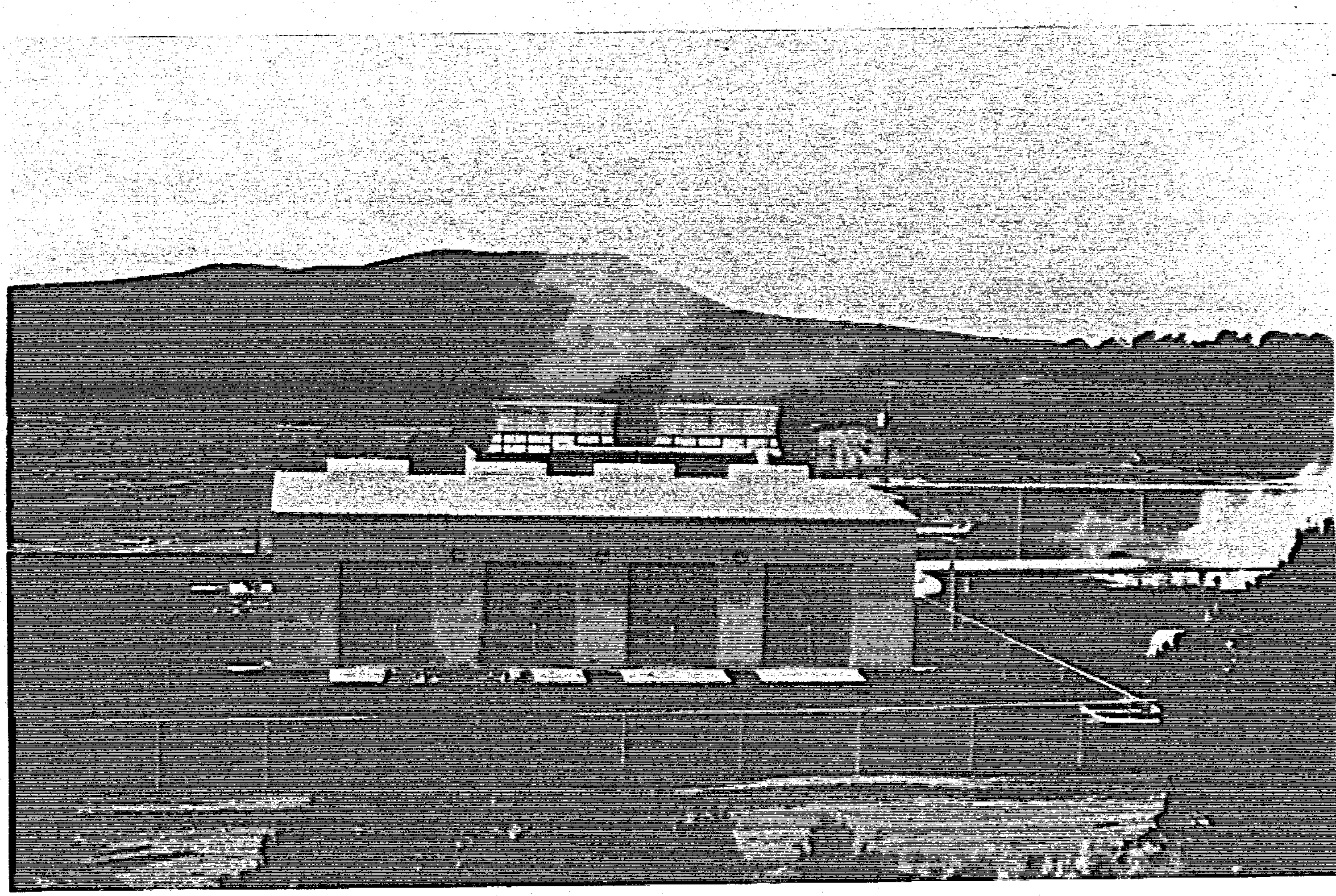

FIGURE 8 :- The 3.2MW Geothermal Power Plant - Sulphurdale

3.5 Modular Cascading Power Plant at Steamboat Springs, Nevada (Fig 9)

a) General Description

The 7.4 MW gross (5 MWe net) G.D.A. Project is located at Steamboat Springs, Nevada. The power from the plant is sold to Sierra Pacific Power Company. The initial start-up was performed in December 1985. Full operation is scheduled for June 1986.

The power plant is composed of seven OEC arranged in a cascading temperature configuration, as shown in Fig. 10. With this arrangement, four high temperature ORC modules receive geothermal water at 334 degrees F (168 deg. C) from the production wells, and three low temperature ORC modules receive geothermal partially cooled water at 284 degrees F (140 deg. C) from the high temperature modules.

The geothermal resourçe is to produce hot water at 334 degrees F (168 deg. C) from two production wells that are equipped with downhole pumps to deliver single phase liquid water under pressure. This hot geothermal water is alkaline and has a total dissolved solids content of about 2,400 ppm, which is mostly chlorides of sodium and potassium with some sulfate, bicardonate, and carbonate, plus about 325 ppm of dissolved silica. The cooled geothermal water will be totally reinjected with none of it consumed in the power generation process.

The hot geothermal water heats and vaporized an organic working fluid, on the shell side of a shell-and-tube preheater-evaporator.

Some 20 percent of the gross power generated is consumed by the fans, pumps, and other auxiliary equipment needed to operate the plant. The balance or net power produced is supplied to Sierra Pacific Power Company grid.

The facility is expected to produce an annual average of 5 MWe (about 44 million kWh per year) electrical power for sale using either evaporative or dry cooling.

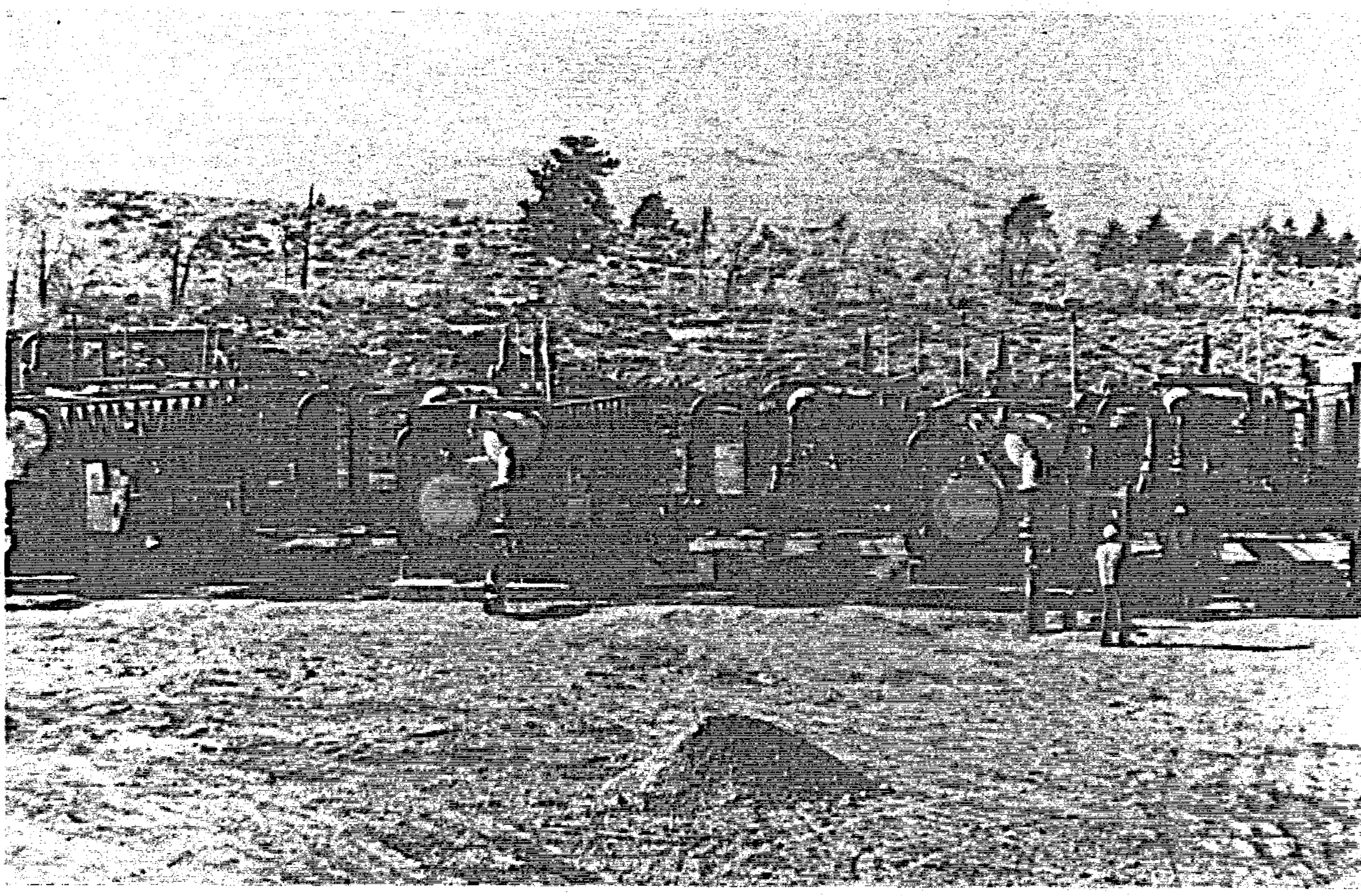

FIGURE 9 : - The 5MW(e) Steamboat Springs Power Plant

b) Design Criteria

Design Basis		
Average annual wet bulb temp	:	43 degrees F (6 deg. C)
Average annual dry bulb temp	:	50 degrees F (10 deg. C)
Cooling water		
Temperature	:	70 degrees F (21 deg. C)
Design source	:	Evaporative tower
Make-up	:	Fresh water from wells
Blowdown disposal	:	Evaporative pond
Geothermal resource (liquid dominated)		
Geothermal hot water temp	:	320 degrees F (160 deg. C)
Flow rate of hot geothermal water	:	1450000 lbs/hr. (660 tons/hr)
Design geothermal water reinjection temperature	:	210 degrees F (99 deg. C)
Disposal rate of geothermal water	:	1450000 lbs/hr. (660 tons/hr)
OEC modules in cascade		
High temperature (Level I)	:	4 @ 1,250 kW capacity
Rated capacity	:	5.0 MWe (gross)
Low temperature (Level II)	:	3 @ 850 kW capacity
Rated capacity	:	2.55 MWe (gross)
Rated generation capacity	:	7.55 MWe (gross)
Projected average generation capacity	:	5.02 MWe (net)
Generator drive	:	Ormat turbine
Condenser	:	Water cooled
Plant requirements		
Operation	:	Continuous base load
Staffing	:	Round-the-clock
Maintenance	:	Days only: individual modules will be taken off line for maintenance
Control	:	Automated with diagnostics and automatic shutdown
Operating life	:	20 years.

The estimated range and annual average generation capacities are summarized as follows:

Range	Gross Capacity
Minimum	6.6 MW
Maximum	8.0 MW
Annual Average (time weighted)	7.25 MW

The time-weighted average mechanical power production capability is based on the power cycle limitations only. Adjustments for any electrical generator limitations, internal power usage, and availability factors are taken into account.

3.6 The 30 MW ORMESA MGPP in the Imperial Valley, California

This site is particularly suitable for ORC for three principal reasons:

(1) The geothermal resource is well documented with exploratory and production wells;

(2) The geothermal fluid is non-corrosive and nearly potable, and

(3) The temperature of the geothermal fluid is approximately 302 degrees F (150 deg. C) to 338 (170 deg. C). ORC modules designed and built by Ormat are particularly well suited for operating temperatures in this range and have a clear competitive advantage over steam turbines.

The project will consist of two major elements: the field, equipped with wells and pumps; and the power plant, with necessary auxiliary systems. The plant is comprised of 26 turbines systems, referred to as Ormat Energy Converter Modules, which will have a capacity of 1.25 ME each. The geothermal fluid is gathered from the wells and then piped to the plant where the energy conversion process take place. Thereafter, the geothermal fluid is reinjected into the field. No geothermal fluid is consumed during the process. The energy conversion process is described in greater detail below.

The field, when fully developed, will include the existing seven production wells and three reinjection wells plus six new wells. The field will also consist of additional production and reinjection wells, down-hole pumps, and a surface piping system to gather the geothermal fluid and transport it to the power plant. After the fluid has been used and cooled, the piping system returns it to the reinjection wells.

The plant consists of 26 ORC modules arranged in 3 levels of cascading units. The gross power generated by the plant will be 30 MW. The electricity will pass through a series of transformers which will upgrade the voltage to a level compatible with the grid system. After utilizing approximately 6 MW for internal usage such as the operation of cooling fans, pumps and plant auxiliary equipment, 24 MW of electrical power will be delivered to the grid.

Approximately 65-70% of the required fluid will come from existing wells. Therefore, only four additional production wells and two injection wells need to be drilled to bring the total continuous flow rate capacity to the required amount of 35 m3 per minute. The project includes a fifth production well to serve as a reserve. The additional production wells will be drilled to depths ranging from 6000 to 7500 ft (2,000 to 2,500 m) in an area immediately south of the existing wells. The additional injection wells will be drilled to a depth of approximately 4,600 ft (1,400 m.)

In order to maintain the production characteristics such as temperature and total flow rate from the field, it will be necessary to periodically drill additional wells. Although the geothermal evaluations project the need of a new well every ten years, it is assumed that a new well will be made every five years.

In December 1985, all existing wells were successfully tested and the first 16 modules were installed on foundations. The plant construction has already started and will be completed by the end of 1986.

4. CONCLUSION

The inherent reliability and low maintenance characteristics of Ormat Organic Rankine Cycle turbogenerators have been demonstrated by the accumulation of over 35 million operating hours in actual field operation.

As power generation costs and industrial power pricing policies outpace the cost of producing such systems, more applications become cost-effective. A well-proven technology exists today. System standardization and series manufacturing will further reduce costs and improve reliability. Standard modules between 400 kW and 1200 kW are commencially available today and are used in modular geothermal plants and industrial waste heat power plants of up to 30 MW.

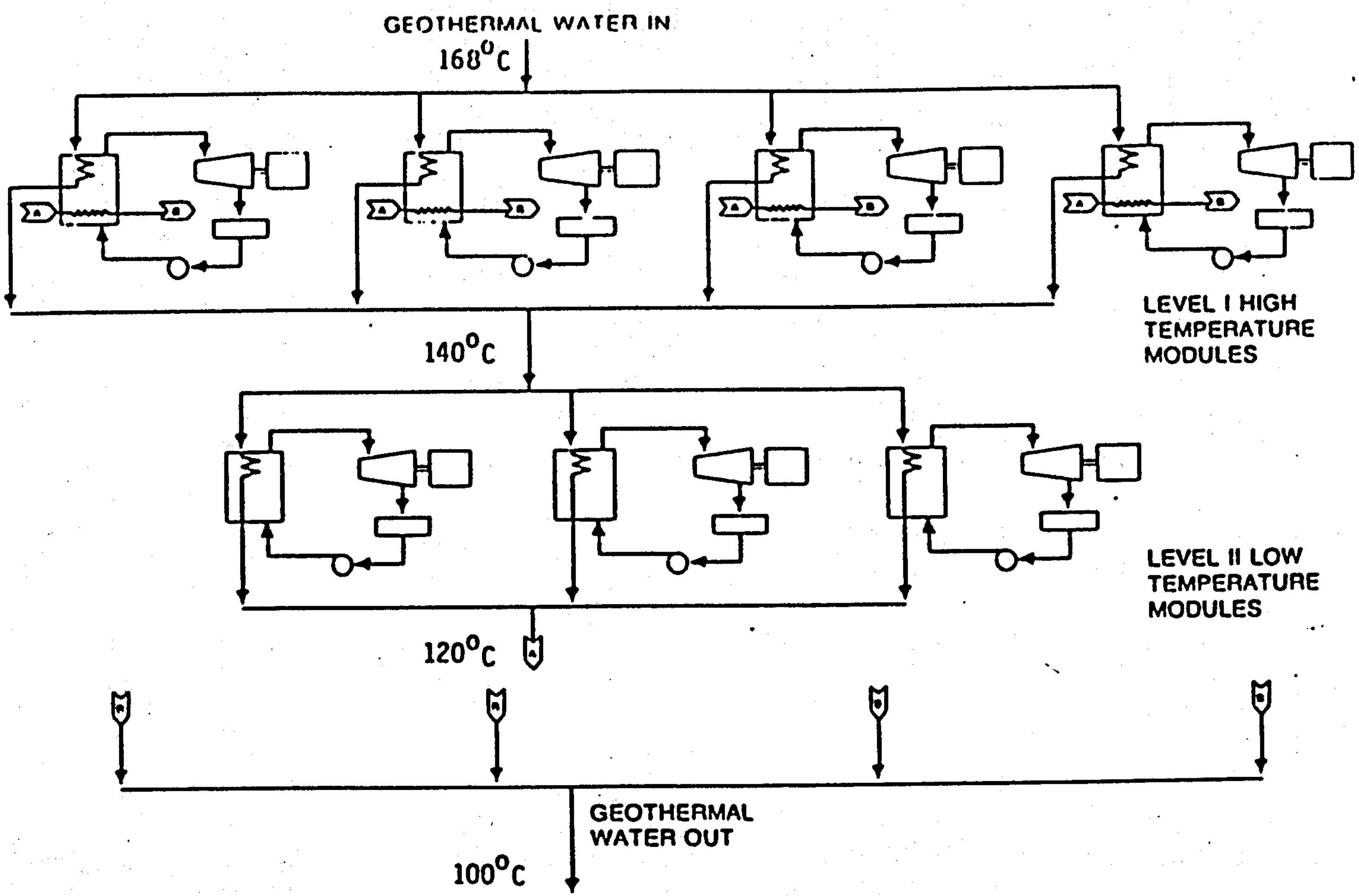

FIGURE 10: Ormat Energy Converter Modules in a Cascading Temperature Arrangement

ROTARY SEPARATOR
(BIPHASE TURBINE CYCLE)

Walter R. Studhalter
Biphase Energy Systems

ABSTRACT:

The Biphase Turbine Cycle utilizes an innovative total-flow expander to produce additional power from given liquid-dominated geothermal wells. This advantage may be used to reduce the number of wells needed in a project, to reduce well flows and thus prolong resource life and to add flexibility to a power plant that operates with changing resource conditions. The geothermal expander, Model 54RST, has been demonstrated in Utah, and applied to geothermal resources in Utah by Utah Power and Light Company, and in Nevada by Phillips Petroleum Company. Biphase was a pioneer in developing the concept of small (wellhead), factory pre-assembled power plant systems.

Careful analysis of additional geothermal resources has led to further development of the Biphase concept:

(a) For high enthalpy and high N.C. gas content, a special adaptation of the Biphase machine featuring a reaction rotor and impulse steam blades.

(b) For rapidly changing resource conditions, the Mitsui-Biphase topping cycle.

(c) For generating additional power from existing flash plants, the larger Model 72RST Biphase geothermal machine.

STATUS OF BIPHASE GEOTHERMAL SYSTEMS:

Biphase Energy Systems began to apply the innovative two-phase turbine to geothermal power plants in 1976. Liquid-dominated resources deliver mixtures of steam and water which are fed together to the Biphase machine to efficiently produce power. After prototype programs sponsored by DOE and Biphase, Utah Power and Light Company and Electric Power Research Institute joined forces in 1980 to test a production version of the geothermal turbine. Performance and endurance tests were successful.

The Model 54RST impulse machine enables systems including a steam turbine to generate 10 to 30 percent more power from given resource flows. The Biphase system using the Model 54RST was also sized so that the power plant could be factory assembled and erected on short schedules near wells. The "wellhead" small power plants were pioneered by Biphase starting in 1980. The idea of employing small plants in multiple has since become dominant in planning for many resource situations, as the papers at this meeting will attest.

Biphase Turbine Cycle

The Biphase turbine cycle substitutes the Biphase Rotary Separator Turbine, a Total Flow Expander (TFE), for a flash tank in the more traditional flash cycles. Figures 1-4 from the recent authoritative paper on TFE (Reference 1) show the single-stage flash and its TFE counterpart, and the two-stage flash and the two-stage TFE system. In the two-stage case, the TFE replaces the low-pressure flash tank. Note that the Biphase Turbine (TFE) also supplies injection pressure, eliminating or minimizing the injection pumping required by the flash systems.

The Biphase cycle is illustrated on a temperature-entropy diagram, Figure 5. Assuming saturated water at point "0", the flash tank isentropic expansion follows path "0-1". The steam produced is separated, point "2g" and expanded in a steam turbine "2g-3" producing power as shown by a change in enthalpy. The Biphase expansion of the liquid follows path "0-2". If 100 percent efficient, the expansion would be isentropic, "0-2i". The Biphase expansion changes enthalpy from "H1" to "H2", thus making power available. Separated steam (slightly less than the isenthalpic case for a classical flash tank) is ducted to the steam turbine, "2g-3".

The additional power produced by Biphase in a single-stage case is shown in Figure 6, also from Reference 1, as a function of wellhead pressure. Note that the specific power of the flash system is constant for any wellhead pressure above P1 = 57 psia, while the specific power of the Biphase system continues to increase with wellhead pressure. Reference 1 contains a set of curves similar to Figure 6 which are useful for estimating many geothermal situations.

The operating principles of the Biphase geothermal turbine are described and illustrated in Reference 2.

Current Projects

Phillips Petroleum Company, Desert Peak, Nevada. The 9 MW power plant at Desert Peak was designed by Phillips Petroleum to utilize a "power skid" which included a Biphase RST and a Transamerica Delaval steam turbine. The skid was fabricated and assembled in Transamerica Delaval's shops in Trenton, New Jersey. The power skid is 13 by 56 feet plan dimensions, weighing 260,000 pounds. The skid was split between the turbine and generator for rail and truck shipment to Desert Peak. This system is described in References 4 and 5, and is the one you will observe on the field trip. Reference 4 states that, for a resource enthalpy of 384 BTU/lbm, the net output power is 10.03 megawatts per million lbm/hr geothermal fluid.

Utah Power & Light, Roosevelt Hot Springs, Utah. Utah Power and Light (UP&L), together with Phillips Petroleum, EPRI and DOE, assisted in the performance and demonstration operations of the Biphase RST at Roosevelt Hot Springs. Using demonstrated performance numbers, UP&L and Southern California Edison Company evaluated the Biphase geothermal system and competing systems in comparison with coal-fired power plants. Comparisons were made on levelized busbar costs. The result is stated (Reference 3), "the only alternative competitive with our coal-fired unit is the RST wellhead system". As a result, UP&L contracted with Biphase Energy Systems for the design of 14.5 MW wellhead systems for the Roosevelt Hot Springs resource, and for delivery of these units as electricity demand requires them.

APPLICATIONS:

I am sure that this audience is well aware that every new geothermal resource is different from all others. Biphase found that their understanding of the technical and economic factors of Biphase and wellhead systems led to proposals which extended Biphase technology in several directions. Three such extensions will be discussed because of current interest in this expanding technology.

Topping Systems

A project involved a geothermal resource with excellent potential for producing power, but with problems caused by very high non-condensible gas content (up to 25 percent), high pressure (40 ata) and high steam quality (0.5 to 0.8). Biphase Energy Systems and their associate, Mitsui Engineering and Shipbuilding Company, designed a system for this resource which preserved the advantages of factory-assembled wellhead modules while being adaptable to the unusual conditions. The special Biphase machine Model was designed to be used in tandem with a Mitsui geothermal steam turbine.

The Biphase topping machine incorporates impulse steam blading, so that the steam kinetic energy is utilized. This addition to the machine design is an adaptation to the high steam content of the resource. This Mitsui-Biphase system helps solve the problem of condensing in the presence of such high inert gas content. Figure 7 shows four cases all with the same well flow at 40 ata pressure. The flash system exhausting to atmosphere (0.8 ata) gives a power level taken as 100. If this plant could be made condensing at 0.2 ata, the power level (RUR: Resource Utilization Ratio) would be 125. Now, the Mitsui-Biphase system, exhausting to atmosphere, gives a power level of 135. Therefore, the atmospheric exhaust is a viable alternative to a condensing flash plant with serious vacuum pumping problems. If the non-condensible gas content decreased in the future, then the Mitsui-Biphase system could be converted to condensing at a Resource Utilization Ratio of 157.

Many geothermal resources present special problems, especially for large central plants, because of anticipated large future changes in resource parameters. We studied a resource in which wellhead pressure is expected to change from 570 psia to 50 psia, and in which enthalpy uncertainty and variation covers the range 600 to 400 BTU/lbm. In this situation, the Biphase RST is useful as a topping device, taking up most variation because of its inherent flexibility so that its tandem steam turbine operates at relatively constant conditions. Figure 8 shows schematically the expected reservoir decline, and the flowrate changes that a Mitsui-Biphase system could accommodate while operating at constant power. The improvement in project life is also indicated schematically in Figure 8.

Figure 9 illustrates an area characterized by Biphase RST inlet pressure and enthalpy, in which a Biphase-Mitsui steam turbine system could elect to operate for 10 MW and 15 MW power plants. If the steam turbine is fixed, with an inlet pressure of 3.5 ata, then range of satisfactory system is shown in Figure 10. When the Biphase inlet pressure is reduced to approximately 10 ata, we would propose to remove it from the system and continue with the steam turbine alone. The Biphase turbine may incorporate impulse steam blading which can improve its efficiency and adaptability.

Bottoming System, UP&L Blundell Power Plant.

Utah Power & Light Company has contracted with Biphase Energy Systems for a design study of a "bottoming" system to be used with the Blundell 20 MW flash plant at Roosevelt Hot Springs, Utah. This existing power plant, Figure 11, disposes of 1,900,000 lb/hr fluid at 345F and 130 psia, which is pumped to injection wells. The Biphase bottoming system is added to this disposal pipeline, as shown, without in any way changing operation of the 20 MW plant or requiring more well flow into the plant. With conditions as shown, the Biphase bottoming plant will deliver 9.78 MW gross, 9.13 MW net electric power to UP&L. This use of otherwise-wasted energy will have very favorable economics.

Larger Capacity

The combination of relatively low enthalpy and high flowrate bottoming plant input are beyond the capacity of the Model 54RST geothermal machine. Accordingly, Biphase Energy Systems designed the next larger frame size, the Model 72RST. In this machine, the primary rotor diameter is 72 inches, in place of 54 inches for the predecessor. The Model 72RST maintains the basic design concept which has proved to have high reliability, and it employs 8 nozzles with internal manifolding in groups of four. There are two fluid inlets into the machine. Also the throttle/stop valves are integral with each nozzle. The Model 72RST can handle flowrates up to 2,500,000 lbm/hr, and thus will complement the Model 54RST in covering a very wide range of applications.

SUMMARY:

Valuable attributes of small power plants, the subject of this meeting, include modular construction, short schedules, flexibility in deployment to match load demands, and low operating and maintenance costs. All of these help improve the owner's cash flow. Biphase Energy Systems has participated in hardware programs which demonstrate advantages of wellhead plants, and also demonstrated that the proprietary Biphase turbine will improve system performance and extend system flexibility and adaptability.

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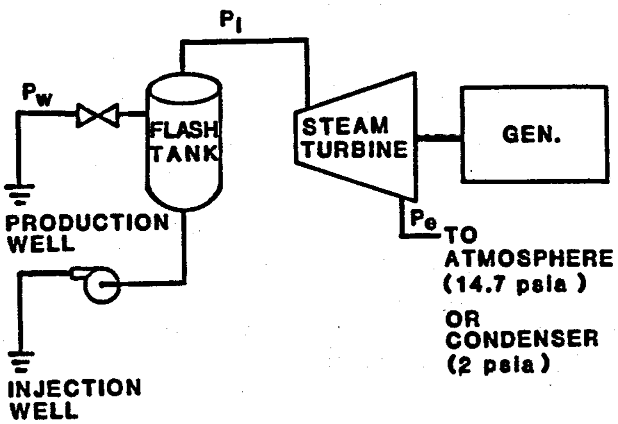

Figure 1. Single-State Flash System Schematic

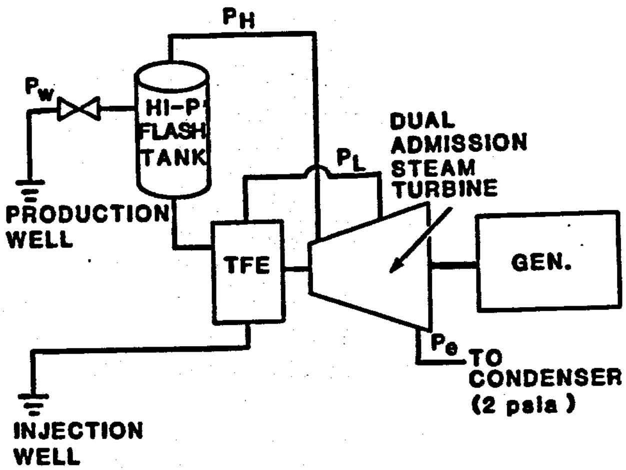

Figure 3. Two-Stage Flash System Schematic

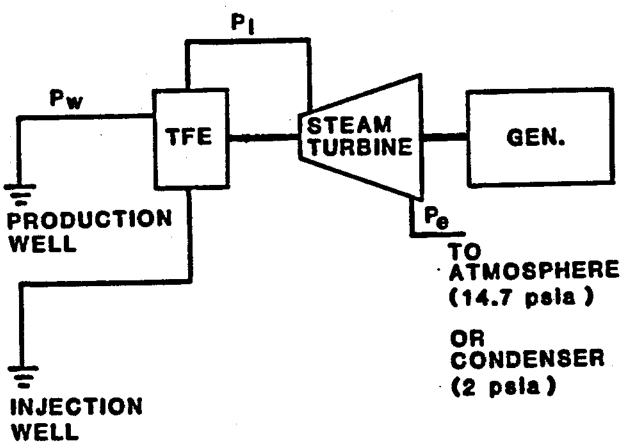

Figure 2. Single-Stage System with TFE

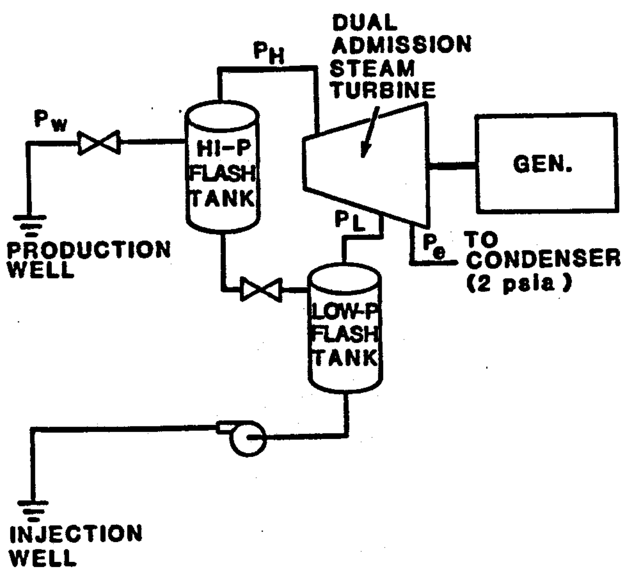

Figure 4. Two-Stage System with TFE

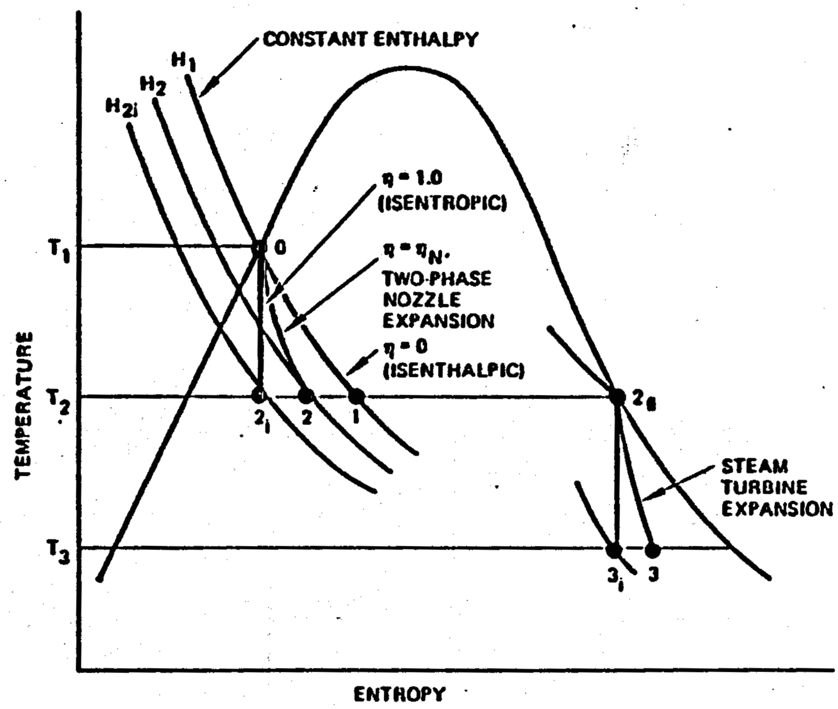

Figure 5. Temperature-Entropy Diagram, Biphase Cycle

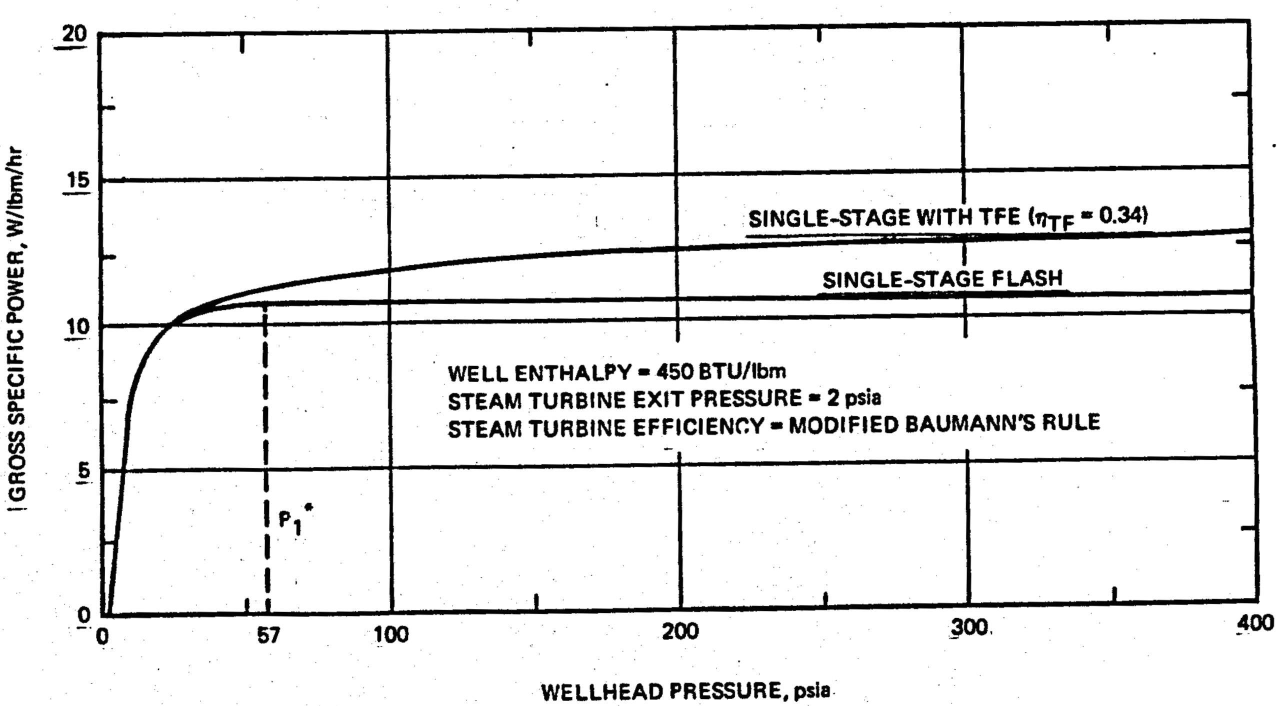

Figure 6. Comparison of Optimized Gross Specific Power Variation with Wellhead Pressure

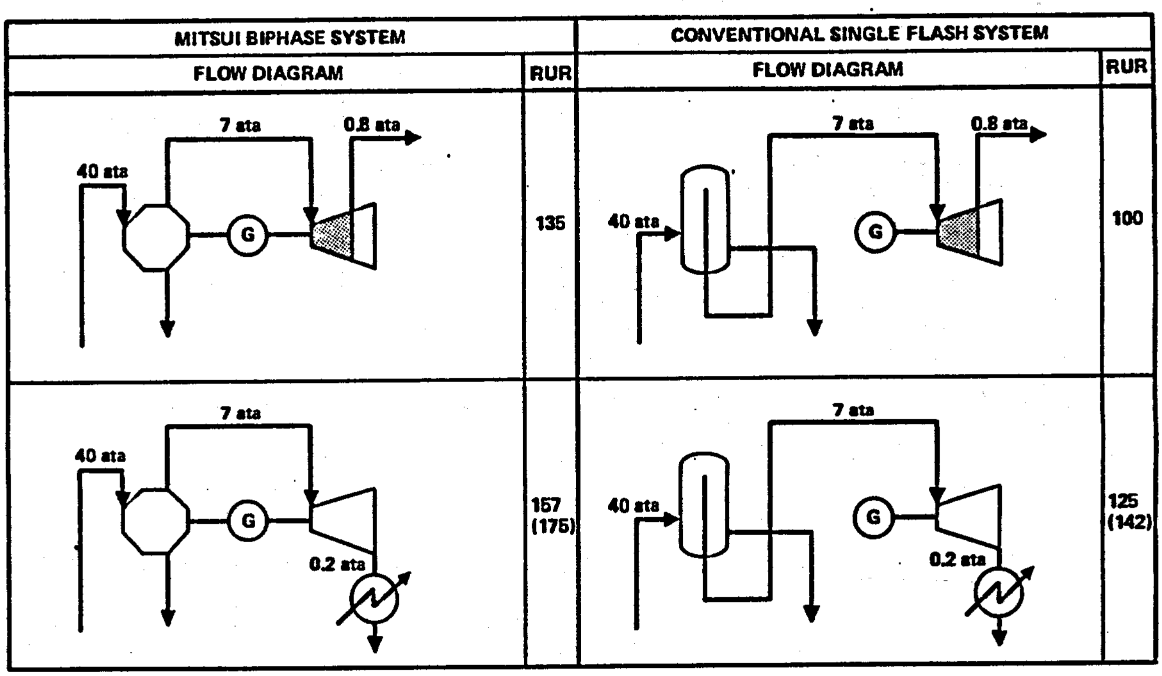

Figure 7. Resource Utilization Comparison for High BTU Resource
RUR = Resource Utilization Ratio

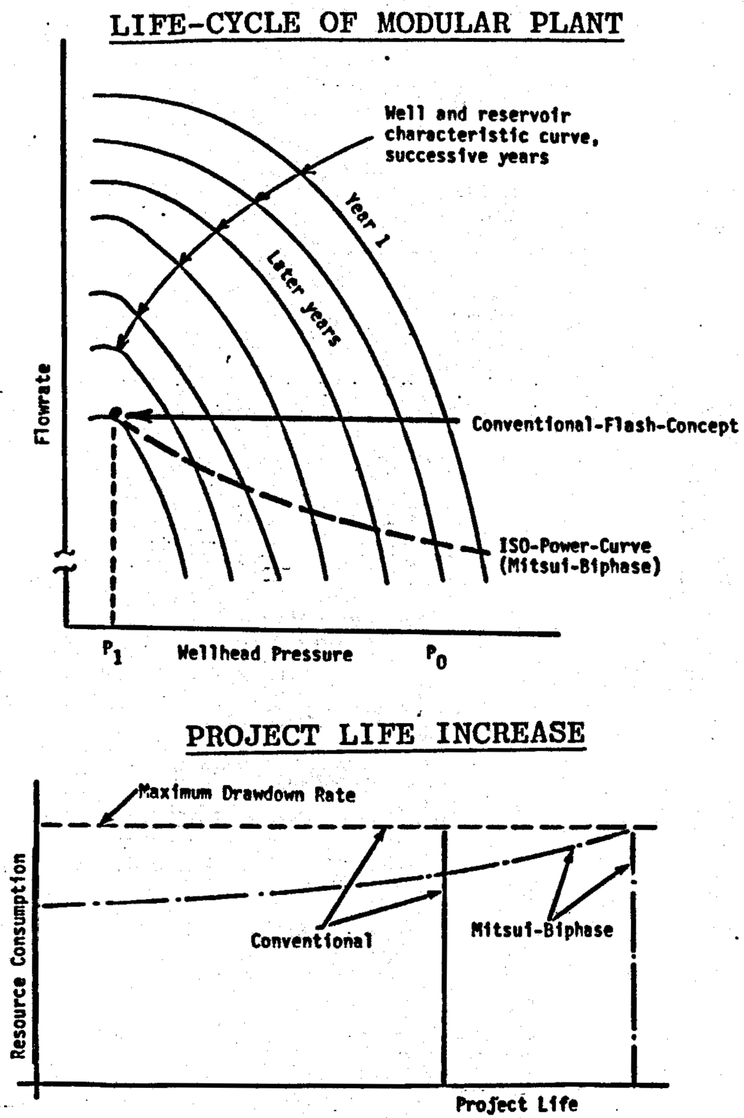

Figure 8. Application of Biphase Cycle to Topping Variable Pressure Resource

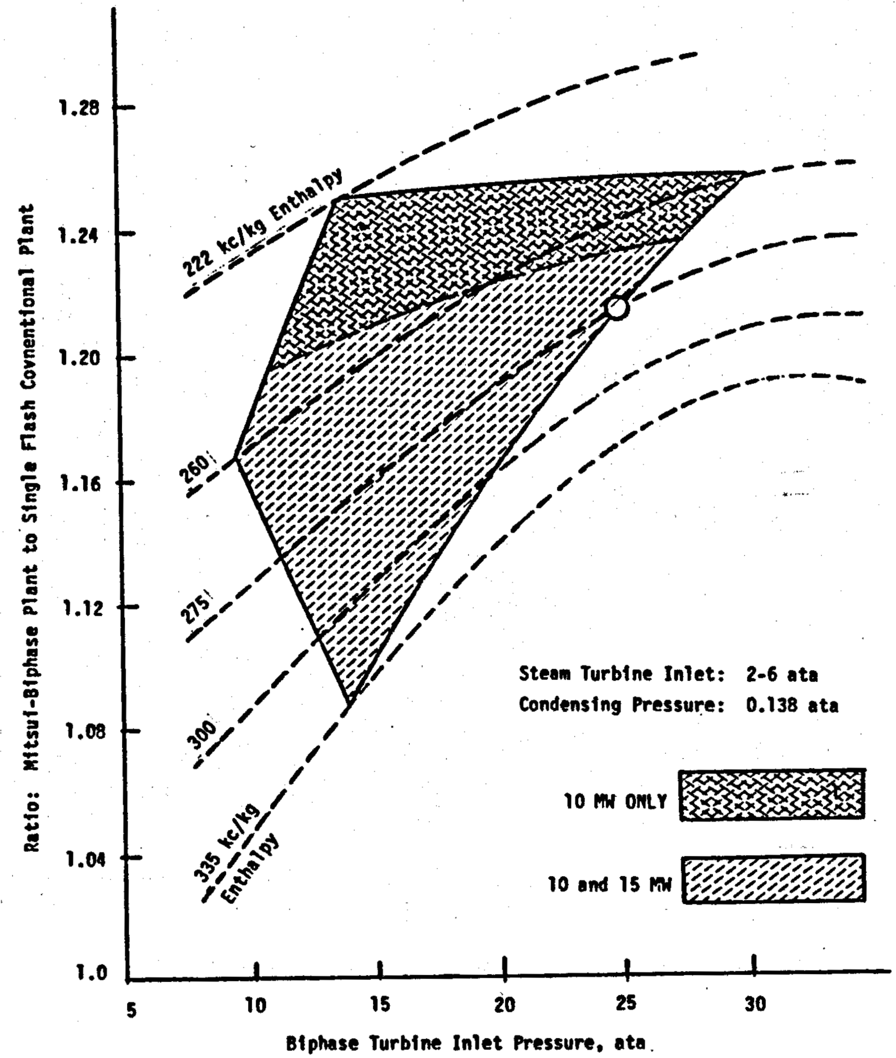

Figure 9. Operating Range Topping System with Biphase Model 54RST

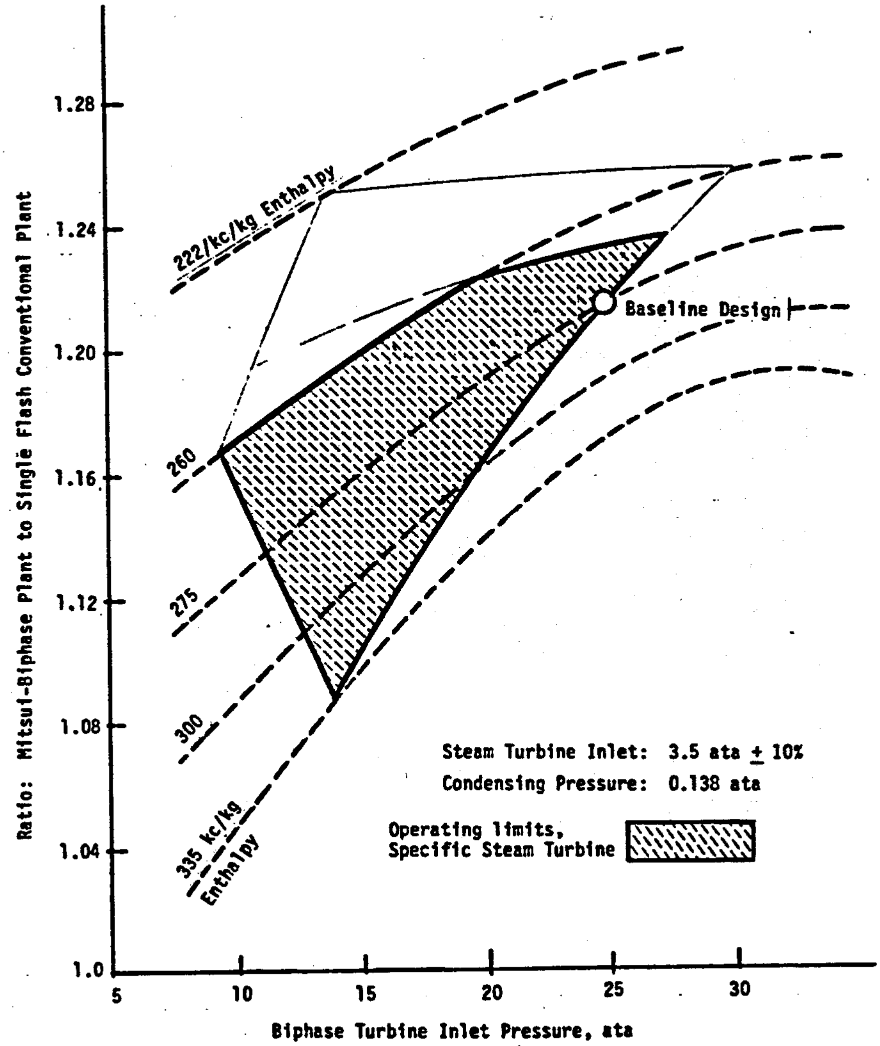

Figure 10. Operating Range of Topping System, Fixed Steam Turbine

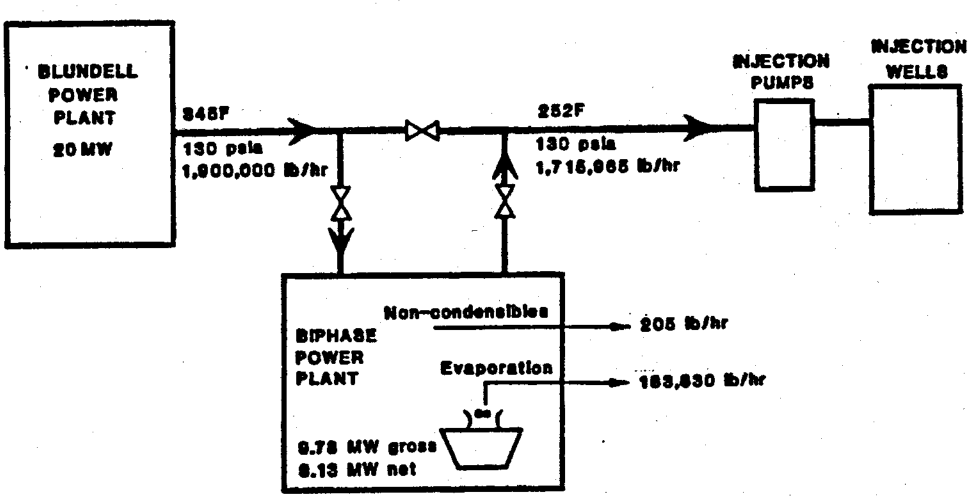

Figure 11. Biphase Bottoming Plant for Blundell Flash Power Plant

HELICAL SCREW EXPANDER POWER PLANT
MODEL 76-1
TEST RESULT ANALYSIS

January 24, 1986

by

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Before attempting an analysis of the test results, a better understanding of the prime mover can be gained by reviewing the theory of operation. Although Model 76-1 utilizes helical screw or Lysholm type rotors, there are two noteworthy features that distinguish it from prior Lysholm type prime movers. Figures 1 and 2 can aid in the understanding of these features and the theory of operation.

The first feature involves the inlet region and method used to fill the high pressure pocket. A variable converging nozzle is located at the rotor endface and appropriately positioned to fill the newly forming pocket. During the initial stages of formation, the pocket pressure (P_1) approaches P0, the inlet pressure. As the pocket becomes fully developed, pressure P_1 decreases to P_2 and a high velocity jet exits from the nozzle throat towards the rotor. The nozzle throat opening is governor controlled and adjusted according to the resource inlet pressure conditions and desired power output. This feature is new and unique to Model 76-1, giving it high volume ratio and pressure ratio capabilities.

The process from P_2 to P_3 is positive displacement expansion with a limited volume ratio. The volume ratio is determined by the rotor profile and inlet nozzle throat opening.

The second noteworthy feature of Model 76-1 involves the rotor pocket opening to the exhaust, P_3 to P_4. Design care was taken to fully open the rotor pocket along both the rotor endface and axially along the rotor tip. Designed thus, the fluids travel through the machine in the straightest possible path. In addition, with square card expansion, the pressure drop from the pocket into the exhaust occurs with a minimum of loss. This feature is important when operation involves low pressure vacuum exhaust.

As stated in the test reports[3,4] on the Helical Screw Expander, Model 76-1 was purposely manufactured with abnormally large clearances. These clearances are more than five times larger than normal for this class of turbomachinery, and it was known that attractive machine efficiencies would require mineral deposition to close the clearances. The impact of these oversized clearances and the resulting leakage is revealed in the following analysis.

The data in Figures 3 and 4 was obtained from the New Zealand test results at a time when the internal clearances were known to be free of any mineral deposition.

Figure 3 contains test data of machine efficiency plotted against the effective fluid volume ratio. Along the right part of the curve, towards point 5, where the high volume ratios occur, the machine becomes increasingly unable to fully expand the fluid across the rotor, resulting in underexpansion and operation known as square card with its known losses. Thus a greater and greater pressure drop occurs from the exit rotor pocket into the exhaust. Along the left of the curve, towards point 1, with low volume ratios, the machine increasingly overexpands the fluid. Thus the exit rotor pocket pressure becomes lower than the exhaust. Near the center of the curve, a point is reached where the machine fully expands the fluid across the rotors and the exit rotor pocket unfolds into the exhaust with no pressure change.

Figure 4, containing the same test data, shows machine efficiency plotted against effective fluid volumetric flow. Again we see the effects of underexpansion along the curve toward point 5. Here, the increasing pressure drop and resulting expansion is shown as increasing volumetric flow. The most important information revealed occurs at full expansion. By definition, at full expansion the exit rotor pocket volumetric flow equals the exhaust volumetric flow - except for leakage. As shown, greater than half the flow through the machine is leakage. With the clearances reduced to a range considered standard for this class of machinery, by a design change or mineral deposition, the leakage rate can be expected to be less than 15% of the total flow.

Figures 5 and 6 contain the same data as Figures 3 and 4, plus two data points from the testing in Mexico. The data points are at the same power outputs and inlet pressure, and differ only as stated in the figures.

The 7/29/80 data point was taken at the conclusion of the endurance testing. Later inspection of the rotors revealed mineral deposition partially closing the clearances.

The 2/06/81 data point was taken after an extended idle period to allow for the conversion to condensing operation. Little or no mineral deposition was observed before or after this data point was obtained. The data point gives no indication of degraded performance due to low pressure exhaust operation.

Figure 7 provides insight into the relationship between clearances and machine efficiency. The figure is from Dr. O. E. Balje and his work on turbomachinery.[4] In the figure, families of machine efficiency are drawn for three different rotor clearances. The rotor length to diameter (L/D) curves are slightly displaced because the diameter is changed (to change the clearance) for each family of curves. Model 76-1 has a leakage gap to rotor diameter ratio (S/D) greater than .004, which is four times larger than the worst case shown on the graph. As can be seen, clearances have a major impact on machine efficiency.

The leakage problem with Model 76-1 makes further analysis of the test results difficult. Leakage is not only a function of clearance, but also a function of clearance distribution through the machine. In addition, pressure drop and distribution across the machine is a factor. Two phase flow also influences leakage. In Figure 4, there is a drop in machine efficiency when going from 50% quality to all steam. The disappearance of liquid phase sealing is clearly evident.

Figures 8 and 9 contain the same data as in Figures 3 and 4, plus data at other power levels. With decreasing power output, the curves peak at lower qualities. At the 316 KW output level, the curve never peaks and the highest efficency is at 0% quality. Here, overexpansion is occurring in all the data points, with 0% quality nearest to full expansion.

Before drawing any conclusions, the influence of mechanical efficiency on performance needs to be included. Model 76-1 was conservatively designed for operation over a broad range of speeds and loads. At 3333 RPM the bearing and seal losses amount to 37 KW. This loss varies predominantly with speed and only slightly with load. At 316 KW the mechanical efficiency is 88.3%; at 560 KW it is 93.4%; and at 663 KW it is 94.4%. Figures 10 and 11 show the results of correcting the curves to the same mechanical efficiency of 94.4%.

It can be reasoned that peak efficiency occurs not at full expansion but with some amount of underexpansion. Here, basically, the addition of a small amount of underexpansion increases the power output faster than the losses. This effect is only slight and should put the point of full expansion slightly to the left of peak efficiency on each curve.

The following observations can be made from Figures 10 and 11. Full expansion and peak efficiency for all loads and qualities occur in a range between 13,800 and 16,000 CFM with machine efficiencies between 41% and 44%. This leads to the following conclusion. If the leakage loss were reduced to 15% of the mass flow, full expansion and peak efficiency for all loads and qualities would occur near 6900 CFM with machine efficiencies above 75%. Stating the conclusion differently, machine efficiencies above 75% can be expected for any quality resource if designed and operated at the appropriate load. Thus, for Model 76-1, with the internal clearances reduced by mineral deposition or a design change, and bearings sized appropriately for the load, operation at 316 KW with 0% quality, at 560 KW with 10% quality, and at 663 KW with 25% quality would all show machine efficiencies above 75%.

The balance of the New Zealand test data broadens the conclusion to include different inlet pressures. In addition, the vacuum exhaust test data from Mexico broadens the conclusion to include vacuum exhaust pressures.

Figures 12, 13 and 14 are based upon the previous conclusion and theory of operation. The curves show the benefits from utilizing underexpansion. All the figures are for the same 72 inch rotor diameter. In Figure 12, the same resource as the Heber binary plant is utilized for comparison. A low grade resource is utilized in Figure 14. With lightweight rotor fabricator techniques, this resource can be viable.

The rotational speeds in Figures 12, 13 and 14 are considered conservative. The upper bounds of speed (tip velocity) and its relationship to dynamic losses or erosion, if any, has not been determined.

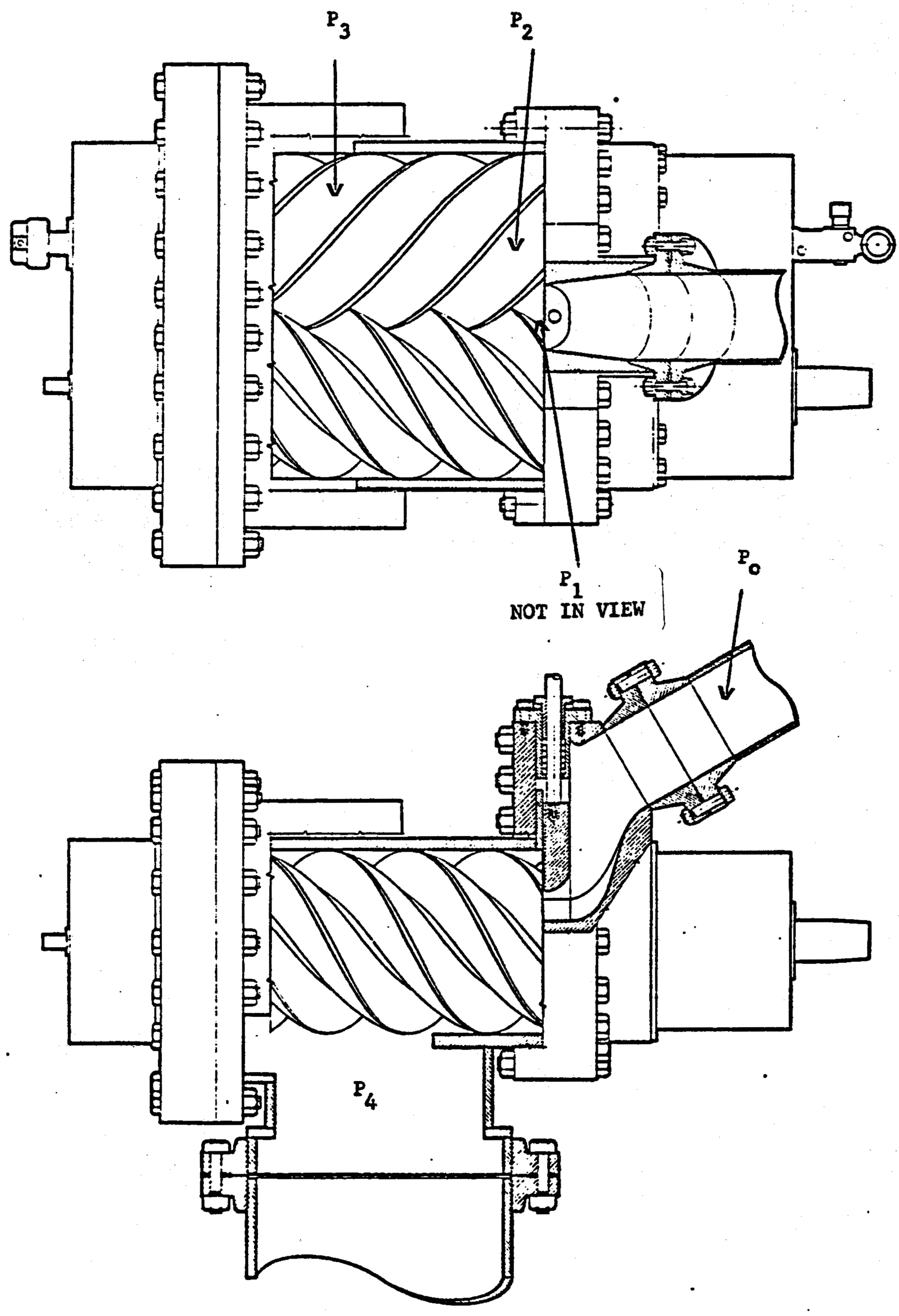
References

1. U.S. Patents 3,977,818 and 3,751,673 and foreign patents held by Hydrothermal Power Co., Ltd.

2. Helical Screw Expander Evaluation Project Final Report, Richard McKay, March 1, 1982, JPL Publication No. 82-5; DOE/ET-28329-1, Distribution Category UC-66D. This report may be ordered under the DOE Accession No. DOE/ET-28329-1, or the NASA Accession No. N82-22659, from the National Technical Information Service (NTIS), U.S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161.

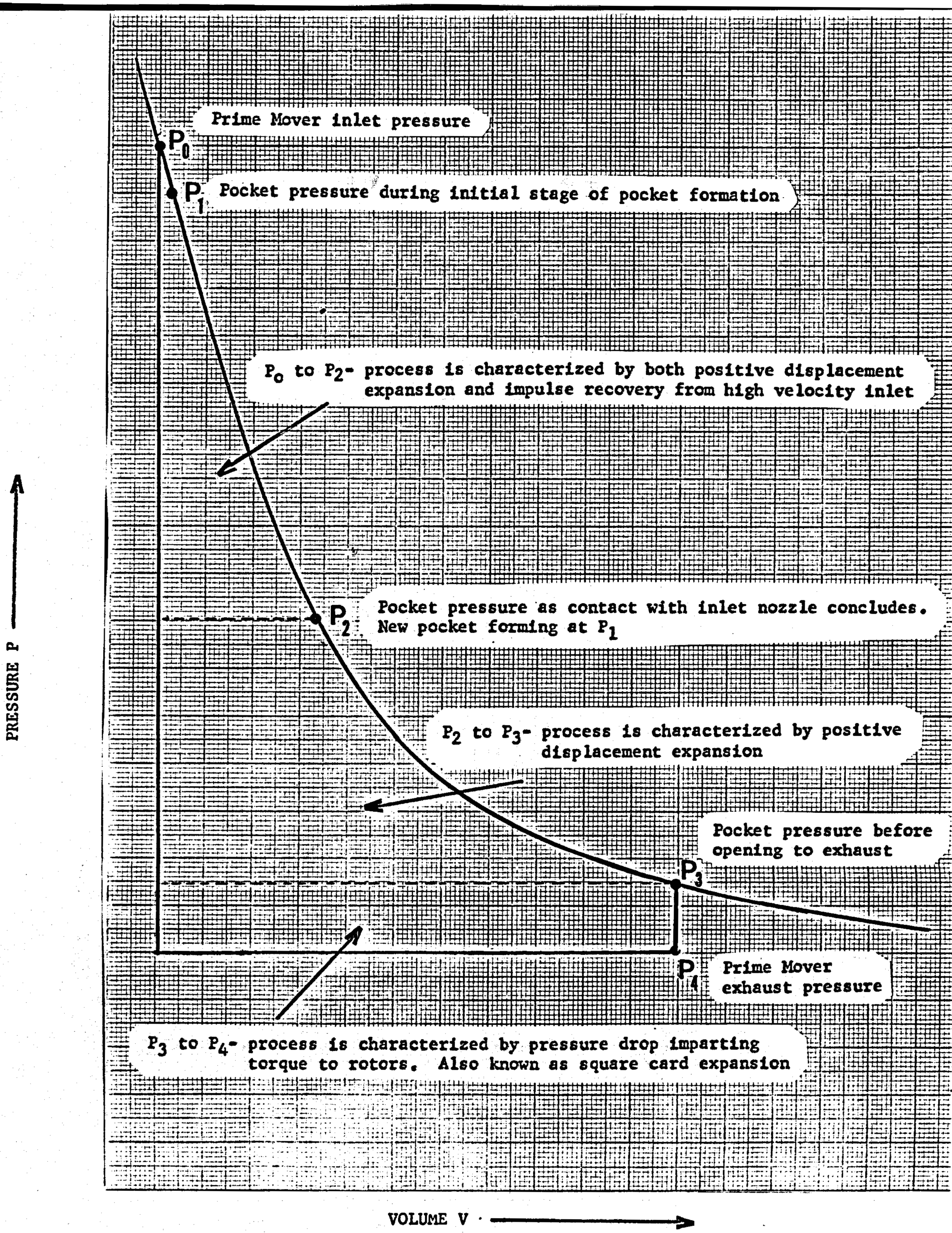
3. International Test and Demonstration of a 1-MW Wellhead Generator: Helical Screw Expander Power Plant, Model 76-1, Final Report, Richard A. McKay, June 1, 1984, JPL Publication No. 84-29; DOE/ET-37116-2, Distribution Category UC-66df.

4. O. E. Balje, Turbomachines: A Guide to Design, Selection and Theory, John Wiley & Sons, Inc., 1981.



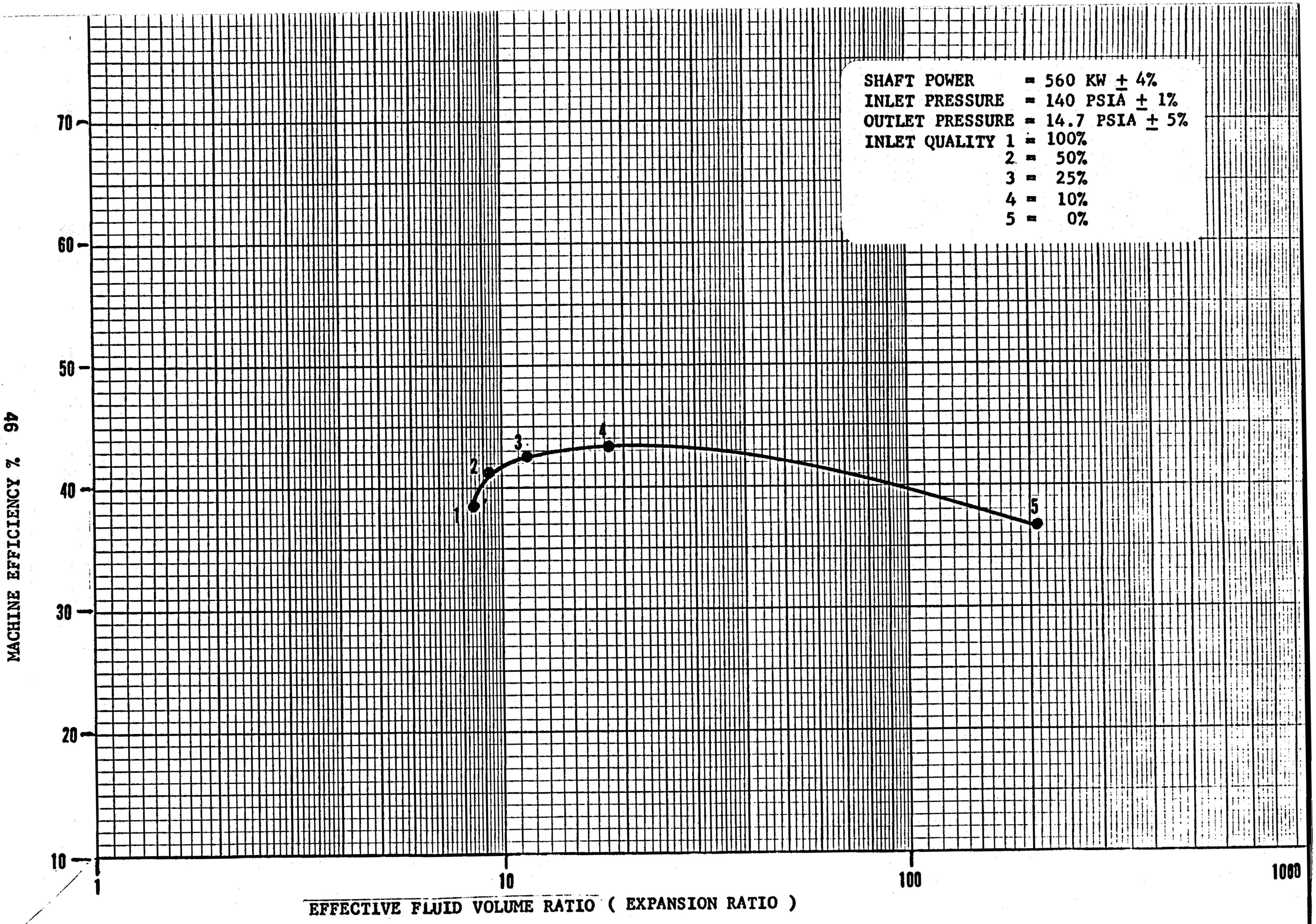
MODEL 76-1

FIGURE 1



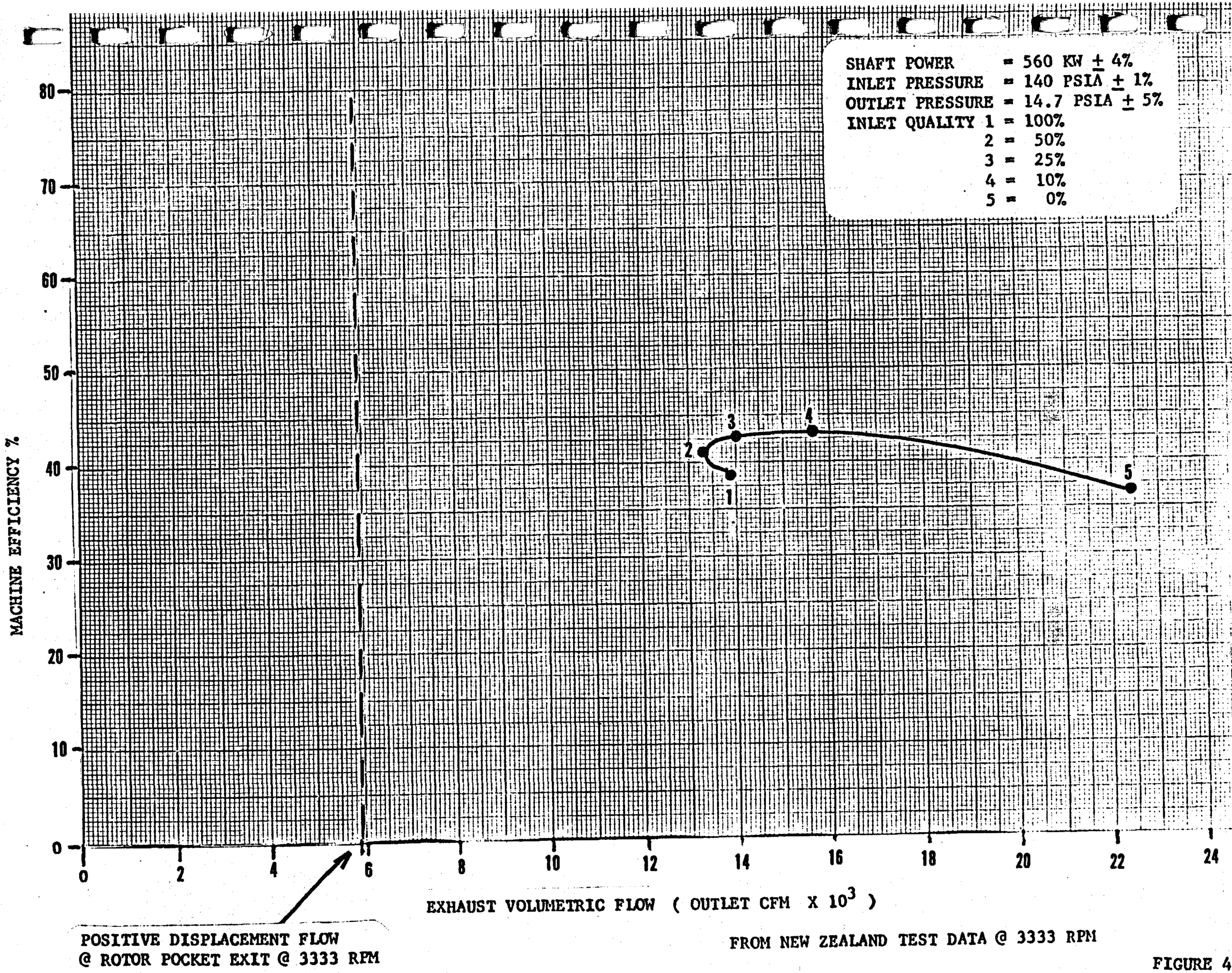
P-V DIAGRAM FOR MODEL 76-1

FIGURE 2



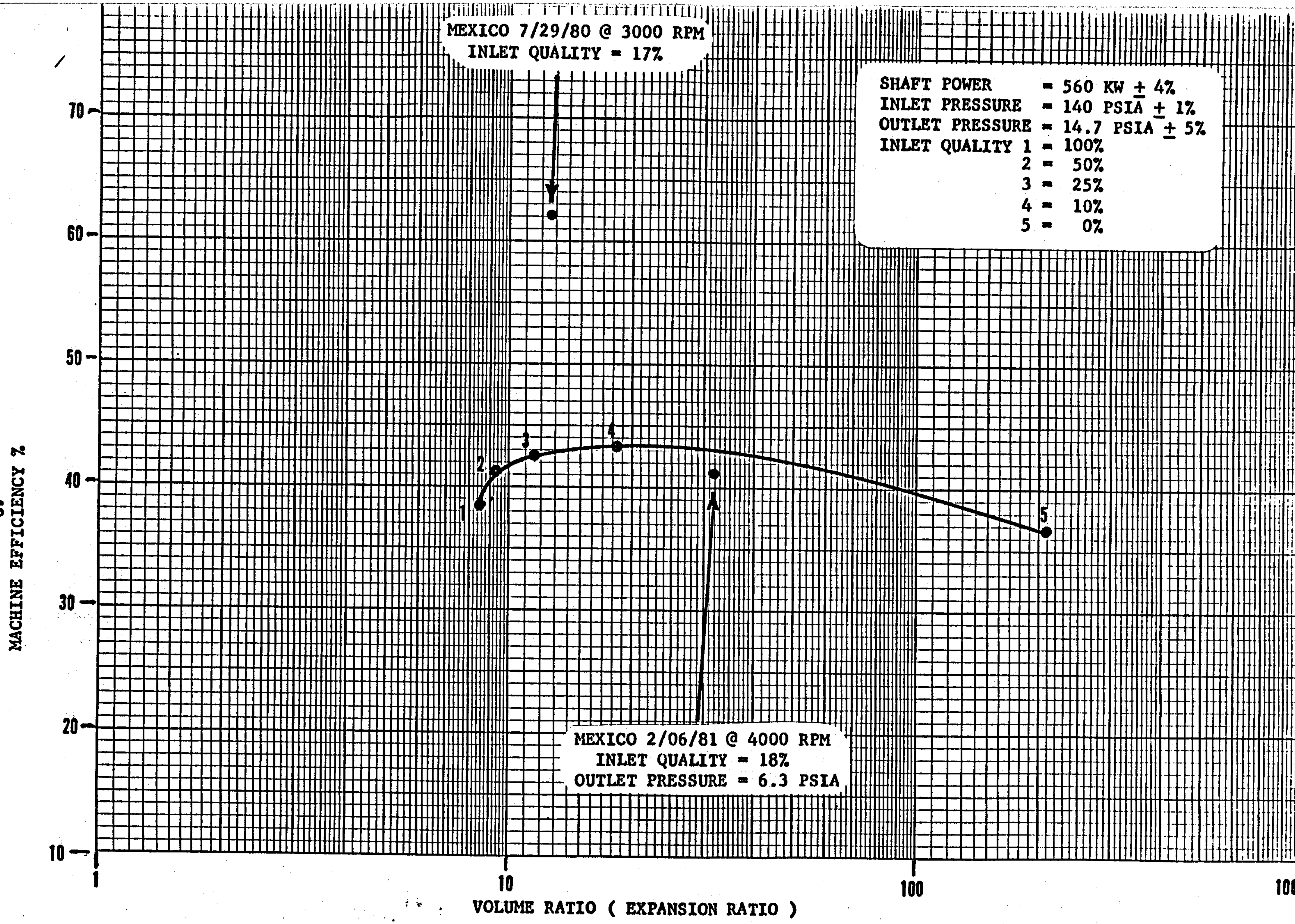
FROM NEW ZEALAND TEST DATA @ 3333 RPM

FIGURE 3



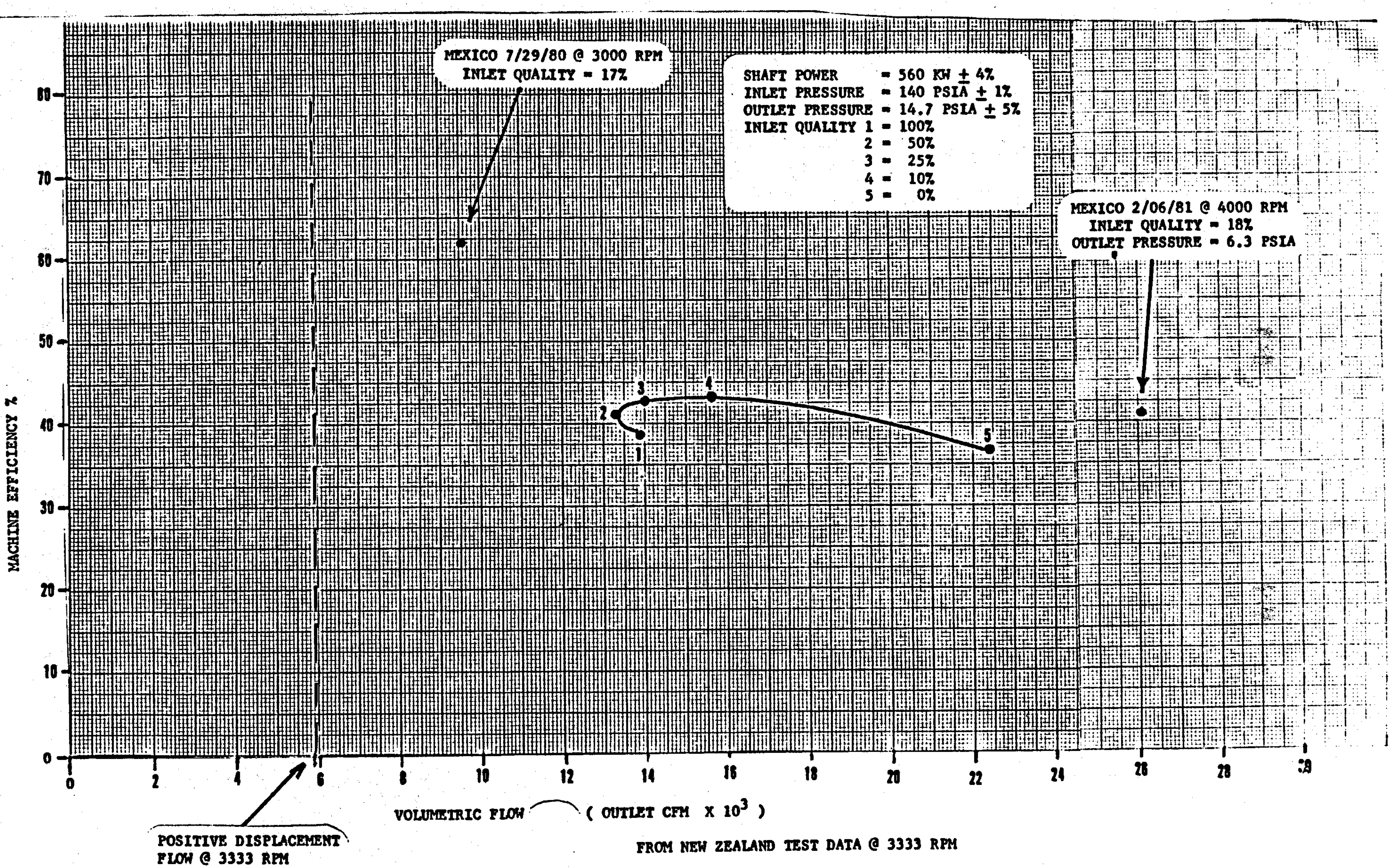
FROM NEW ZEALAND TEST DATA @ 3333 RPM

FIGURE 4



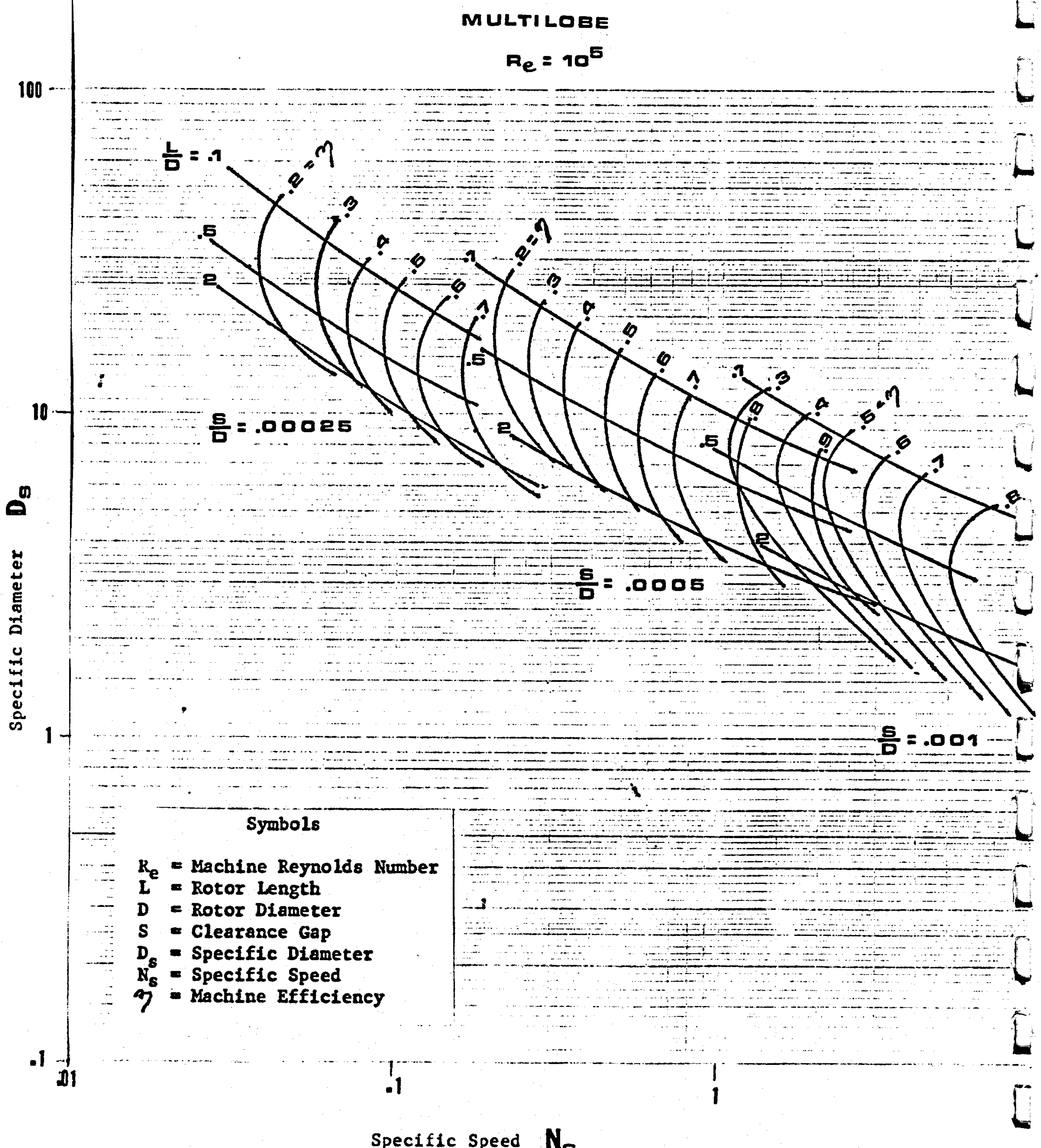
FROM NEW ZEALAND TEST DATA @ 3333 RPM

FIGURE 5



MEXICO 7/29/80 @ 3000 RPM
INLET QUALITY = 17%
SHAFT POWER = 560 KW ± 4%
INLET PRESSURE = 140 PSIA ± 1%
OUTLET PRESSURE = 14.7 PSIA ± 5%
INLET QUALITY 1 = 100%
2 = 50%
3 = 25%
4 = 10%
5 = 0%
MEXICO 2/06/81 @ 4000 RPM
INLET QUALITY = 18%
OUTLET PRESSURE = 6.3 PSIA
MACHINE EFFICIENCY %
0
10
20
30
40
50
60
70
80
1
2
3
4
5
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
VOLUMETRIC FLOW (OUTLET CFM X 10^3)
POSITIVE DISPLACEMENT FLOW @ 3333 RPM
FROM NEW ZEALAND TEST DATA @ 3333 RPM

FIGURE 6



(after O.E. Balje)

Figure 3.

FIGURE 7

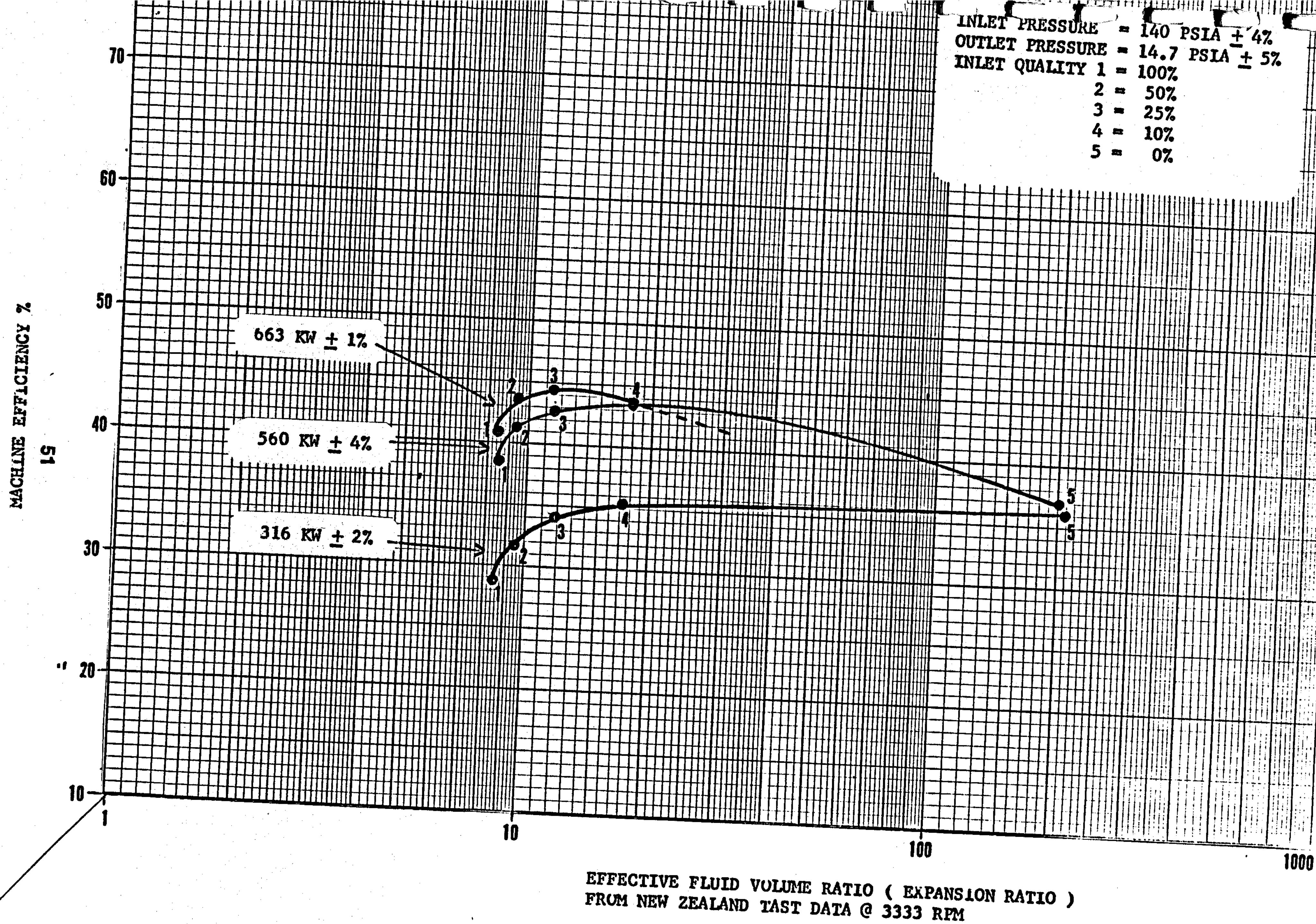

INLET PRESSURE = 140 PSIA ± 4%
OUTLET PRESSURE = 14.7 PSIA ± 5%
INLET QUALITY 1 = 100%
2 = 50%
3 = 25%
4 = 10%
5 = 0%
663 KW ± 1%
560 KW ± 4%
316 KW ± 2%
MACHINE EFFICIENCY %
EFFECTIVE FLUID VOLUME RATIO (EXPANSION RATIO)
FROM NEW ZEALAND TAST DATA @ 3333 RPM

FIGURE 8

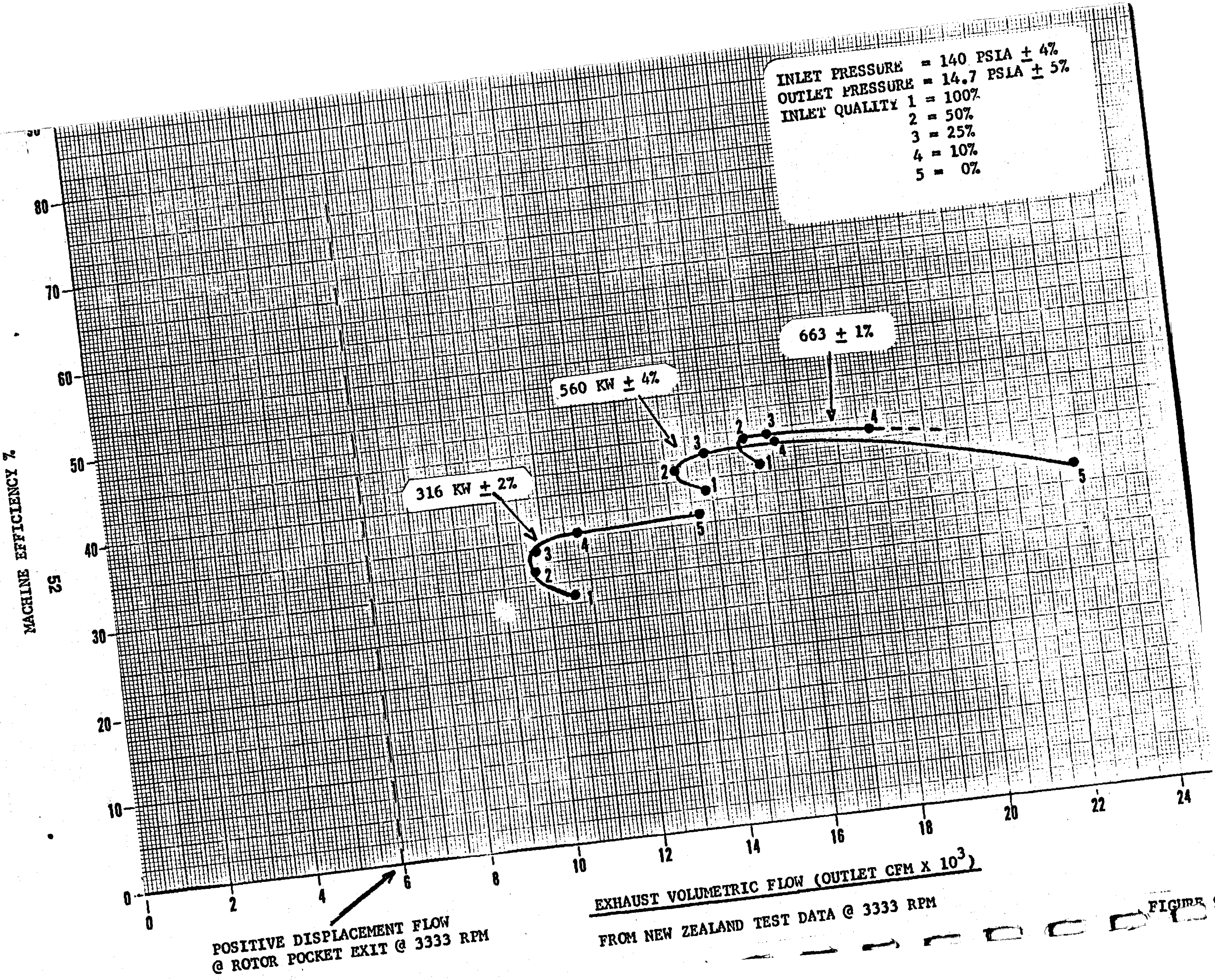

INLET PRESSURE = 140 PSIA ± 4%
OUTLET PRESSURE = 14.7 PSIA ± 5%
INLET QUALITY 1 = 100%
2 = 50%
3 = 25%
4 = 10%
5 = 0%
663 ± 1%
560 KW ± 4%
316 KW ± 2%
MACHINE EFFICIENCY %
0
10
20
30
40
50
60
70
80
0
2
4
6
8
10
12
14
16
18
20
22
24
EXHAUST VOLUMETRIC FLOW (OUTLET CFM X 10^3)
FROM NEW ZEALAND TEST DATA @ 3333 RPM
POSITIVE DISPLACEMENT FLOW
@ ROTOR POCKET EXIT @ 3333 RPM

FIGURE 9

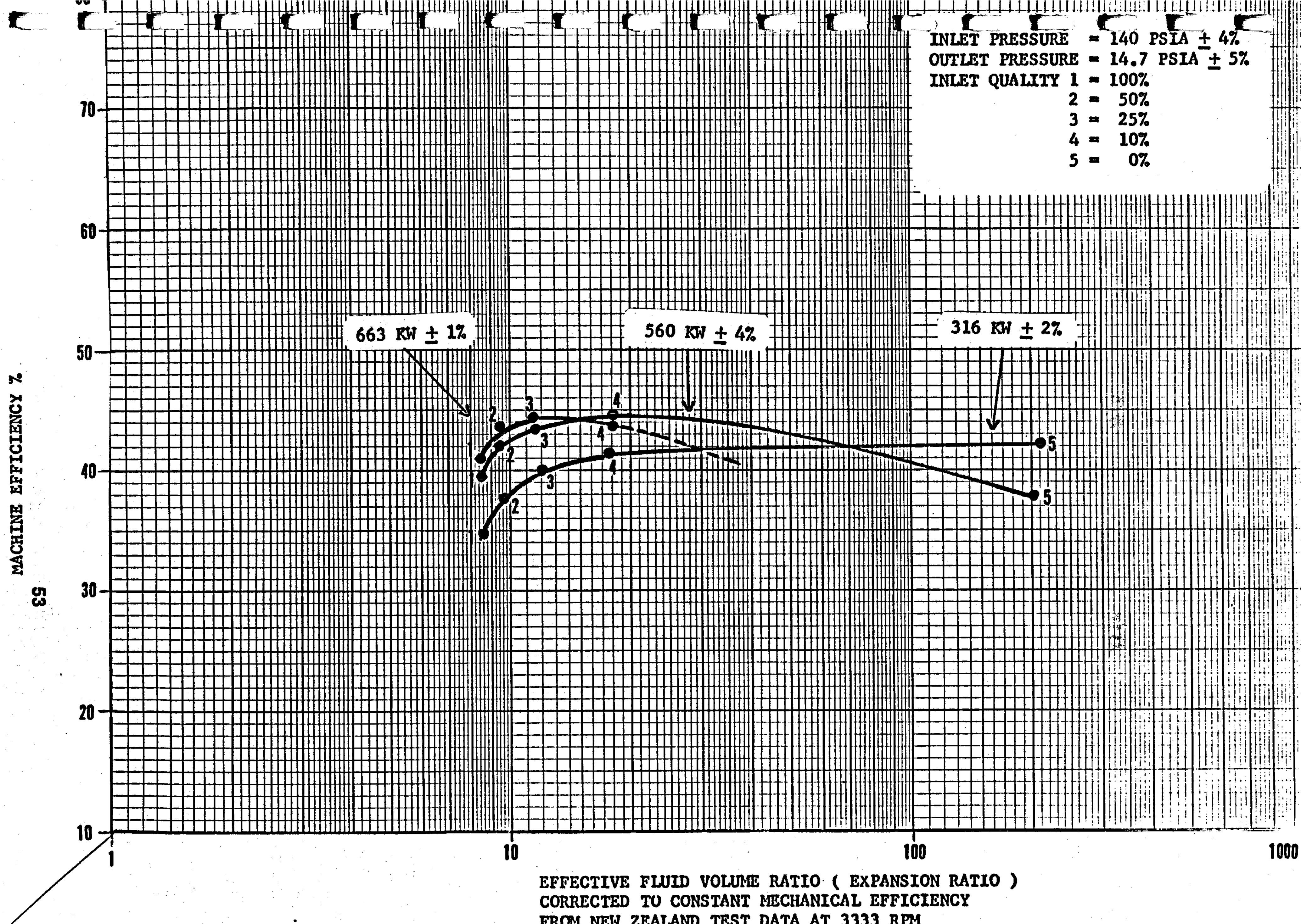

INLET PRESSURE = 140 PSIA ± 4%
OUTLET PRESSURE = 14.7 PSIA ± 5%
INLET QUALITY 1 = 100%
2 = 50%
3 = 25%
4 = 10%
5 = 0%
663 KW ± 1%
560 KW ± 4%
316 KW ± 2%
MACHINE EFFICIENCY %
70
60
50
40
30
20
10
1
10
100
1000
EFFECTIVE FLUID VOLUME RATIO (EXPANSION RATIO)
CORRECTED TO CONSTANT MECHANICAL EFFICIENCY
FROM NEW ZEALAND TEST DATA AT 3333 RPM

FIGURE 10

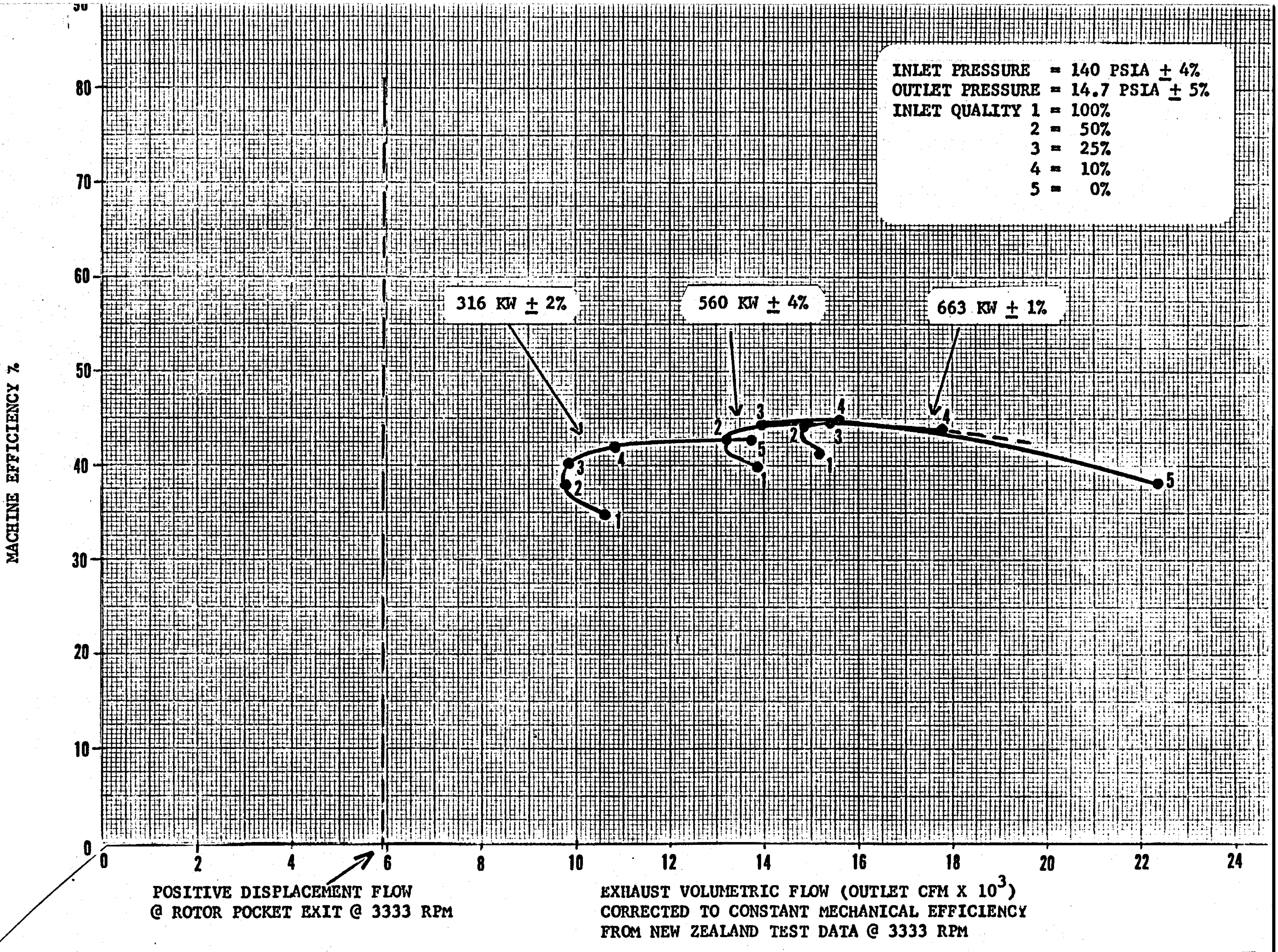

INLET PRESSURE = 140 PSIA ± 4%
OUTLET PRESSURE = 14.7 PSIA ± 5%
INLET QUALITY 1 = 100%
2 = 50%
3 = 25%
4 = 10%
5 = 0%
316 KW ± 2%
560 KW ± 4%
663 KW ± 1%
MACHINE EFFICIENCY %
POSITIVE DISPLACEMENT FLOW
@ ROTOR POCKET EXIT @ 3333 RPM
EXHAUST VOLUMETRIC FLOW (OUTLET CFM X 10³)
CORRECTED TO CONSTANT MECHANICAL EFFICIENCY
FROM NEW ZEALAND TEST DATA @ 3333 RPM

FIGURE 11

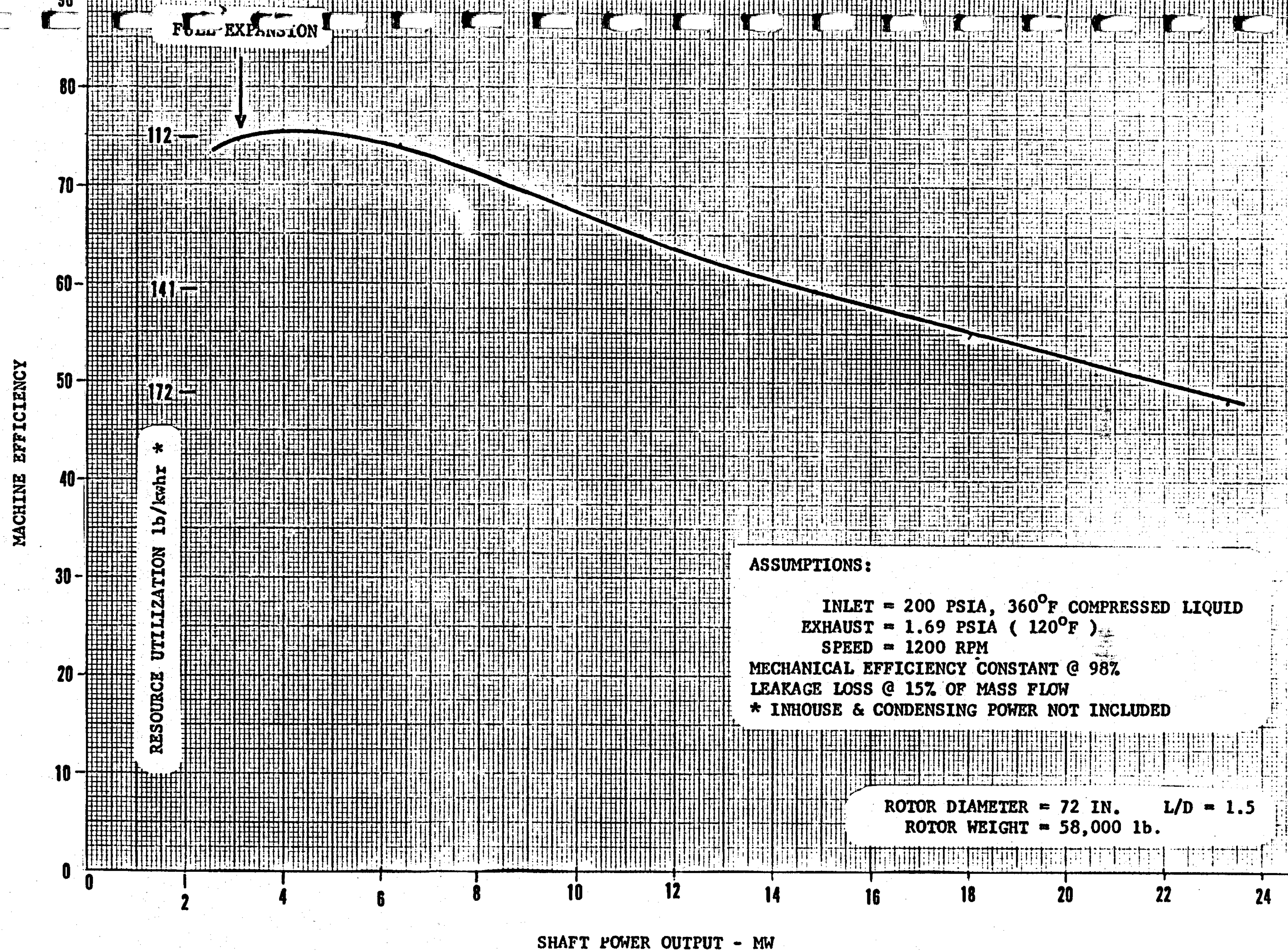

FULL EXPANSION
MACHINE EFFICIENCY
RESOURCE UTILIZATION lb/kwhr *
112
141
172
0
10
20
30
40
50
60
70
80
0
2
4
6
8
10
12
14
16
18
20
22
24
SHAFT POWER OUTPUT - MW
ASSUMPTIONS:
INLET = 200 PSIA, 360°F COMPRESSED LIQUID
EXHAUST = 1.69 PSIA (120°F)
SPEED = 1200 RPM
MECHANICAL EFFICIENCY CONSTANT @ 98%
LEAKAGE LOSS @ 15% OF MASS FLOW
* INHOUSE & CONDENSING POWER NOT INCLUDED
ROTOR DIAMETER = 72 IN. L/D = 1.5
ROTOR WEIGHT = 58,000 lb.

FIGURE 12

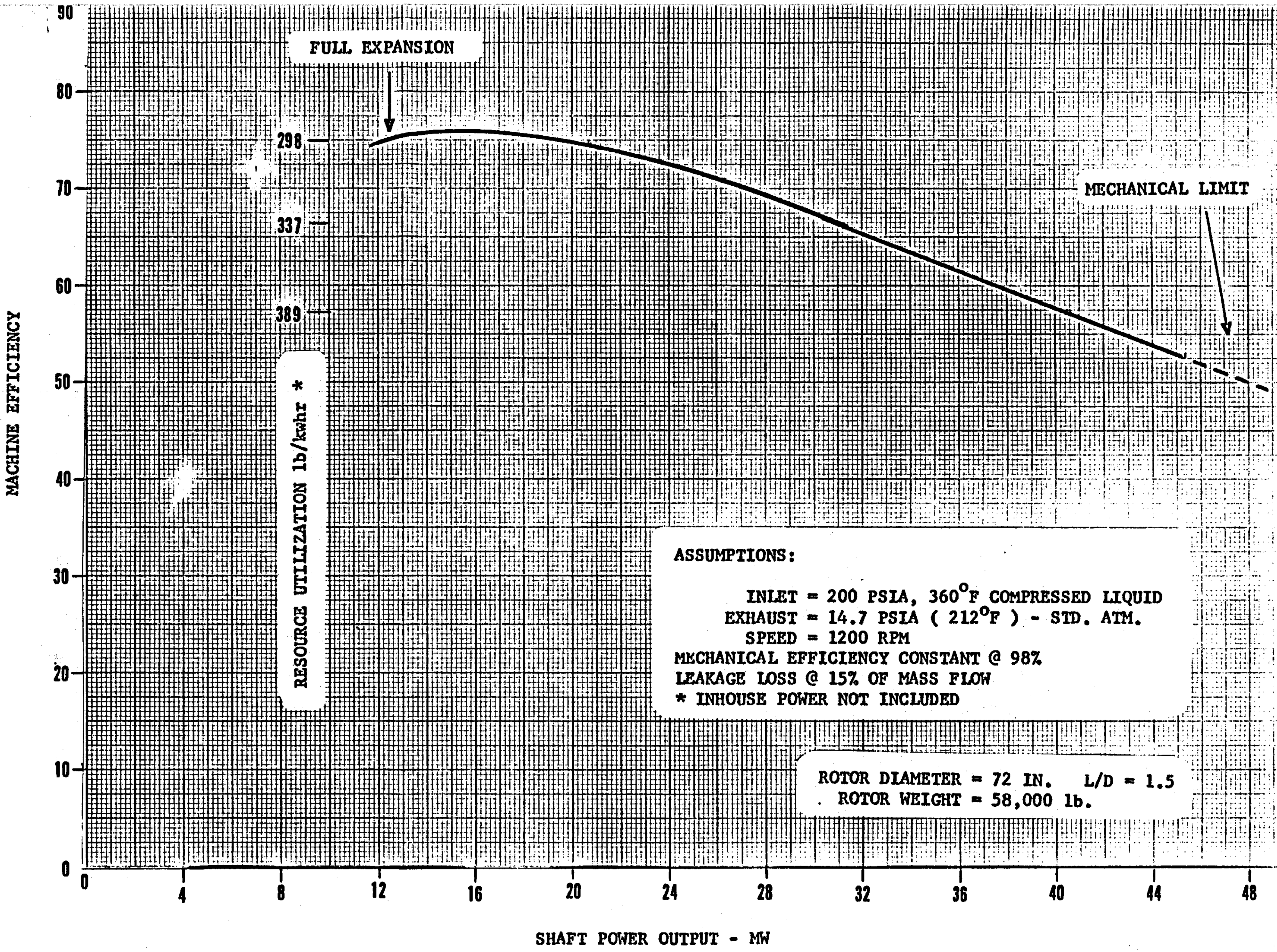
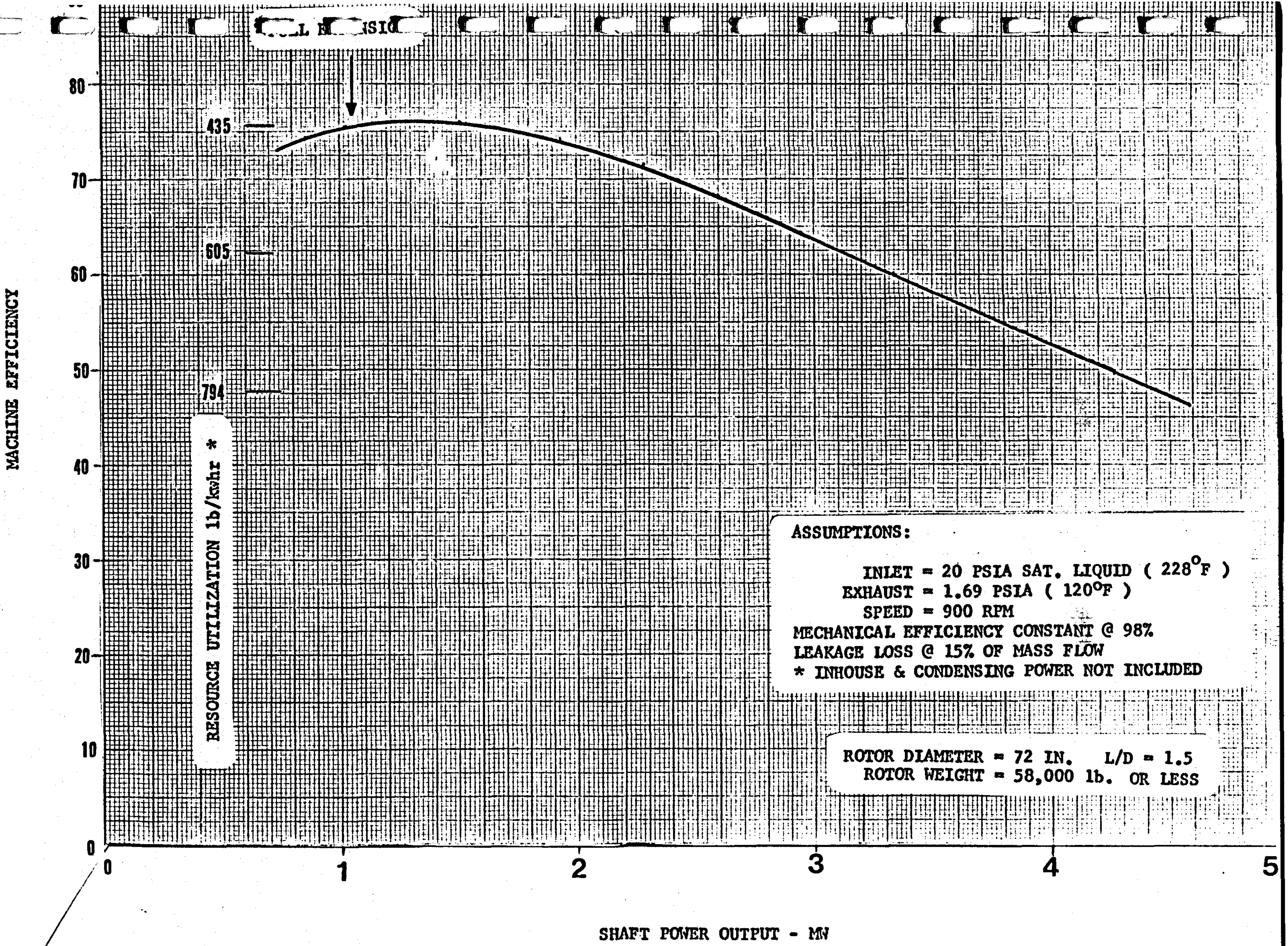

FULL EXPANSION
MECHANICAL LIMIT
MACHINE EFFICIENCY
90
80
70
60
50
40
30
20
10
0
298
337
389
RESOURCE UTILIZATION lb/kwhr *
ASSUMPTIONS:
INLET = 200 PSIA, 360°F COMPRESSED LIQUID
EXHAUST = 14.7 PSIA (212°F) - STD. ATM.
SPEED = 1200 RPM
MECHANICAL EFFICIENCY CONSTANT @ 98%
LEAKAGE LOSS @ 15% OF MASS FLOW
* INHOUSE POWER NOT INCLUDED
ROTOR DIAMETER = 72 IN. L/D = 1.5
ROTOR WEIGHT = 58,000 lb.
0
4
8
12
16
20
24
28
32
36
40
44
48
SHAFT POWER OUTPUT - MW

FIGURE 13



MACHINE EFFICIENCY
RESOURCE UTILIZATION lb/kwhr *
0
10
20
30
40
50
60
70
80
435
605
794
0
1
2
3
4
5
SHAFT POWER OUTPUT - MW
ASSUMPTIONS:
INLET = 20 PSIA SAT. LIQUID (228°F)
EXHAUST = 1.69 PSIA (120°F)
SPEED = 900 RPM
MECHANICAL EFFICIENCY CONSTANT @ 98%
LEAKAGE LOSS @ 15% OF MASS FLOW
* INHOUSE & CONDENSING POWER NOT INCLUDED
ROTOR DIAMETER = 72 IN. L/D = 1.5
ROTOR WEIGHT = 58,000 lb. OR LESS

FIGURE 14

MODULAR WELLHEAD POWER PLANTS

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Arvada, CO 80002

ABSTRACT

Geothermal wellhead power plants, based on the organic Rankine cycle, can provide very reliable power with high utilization of the avialable resource. The power cycle is adaptable to water or steam resource temperatures of 180°F to 350°F. The power plant cycle working fluid is a halogenated hydrocarbon refrigerant that is selected to provide the best overall performance as a function of resource temperature. Each power plant consists of one module which contains all of the heat exchangers, power turbine, alternator and controls. The power plant can generate from 300 kW to 1000 kW, depending on resource temperature. The larger size plants utilize one additional heat rejection module. Multiple plants can be located at the wellhead, producing several megawatts if the energy is available. These plants can be on line in approximately six months from project initiation.

CYCLE DISCUSSION

The wellhead power plant is referred to as a "Power Generation Module" or PGM for short. The principle of operation is described as follows:

Water is used for the working fluid in large utility power plants. The low molecular weight of water requires multi-stage turbines to obtain high efficiency. For Rankine engines with heat source temperatures below 800°F, organic fluids with molecular weights greater than that of water can provide high cycle efficiency and result in simpler and less costly single-stage expanders. The working fluid is a halocarbon-type refrigerant that is nontoxic, nonflammable and readily available.

SIMPLIFIED RANKINE CYCLE SCHEMATIC

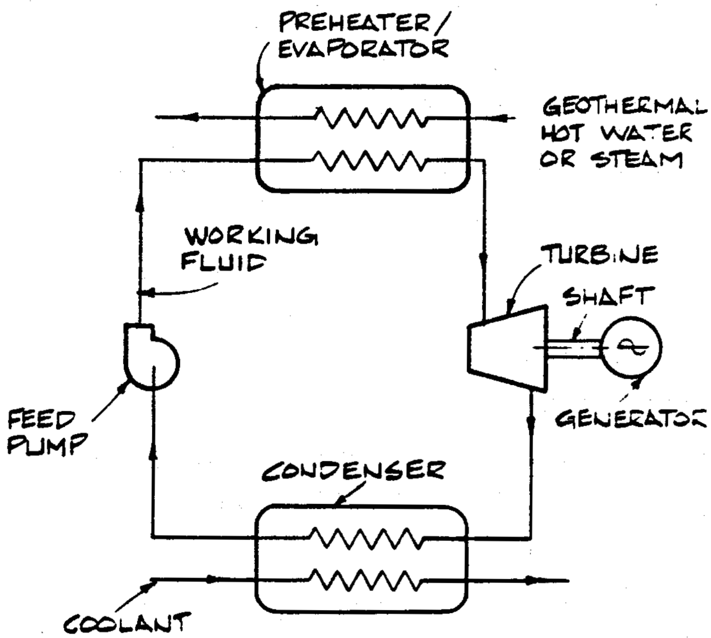


FIGURE 1

The PGM is based on the Rankine power cycle concept. This is the same basic cycle used by utilities in their steam generating plants. The main components of a simplified Rankine cycle are shown in the schematic of Figure 1. It consists of heat exchangers (the preheater/evaporator) which transfers energy from a heat source (such as geothermal hot water or steam) to the working fluid. The heat supplied is sufficient to completely vaporize the working fluid which is at a relatively high pressure. The vaporized working fluid is expanded through a turbine where shaft power is produced to drive a generator and thus produce electricity. The working fluid then flows to the condenser where heat is rejected to a heat sink (such as the evaporation of water or ambient air) and the working fluid is condensed. The liquid working fluid is pumped from the condenser back to the preheater/evaporator, thus completing the cycle.

The major components of the PGM include the heat exchangers, rotating machinery and a control system for the automatic startup and operation of the PGM. The major components are all assembled into one module and then shipped to the site for installation. This approach maximizes the factory work done under well-equipped conditions and minimizes the expensive field work. The PGM is tailored to match the resource so the details can vary from one installation to another.

POWER POTENTIAL

The generating potential of a geothermal resource for various geothermal hot water temperatures and flow rates is shown in Figure 2. Knowing the geothermal water temperature and flowrate, one can use this figure to estimate the potential power output. As an example, assume a geothermal resource has a liquid temperature of 250°F and flows at 300 gpm. From Figure 2, the resource could generate 330 kW of electrical power. It should be noted that the power output in this figure is net output power, i.e., the PGM parasitic loads such as the condenser and feed pump power have been accounted for; geothermal pumping requirements, if any, have not been accounted for. Single PGM's can handle flow rates up to 1000 gpm. Multiple PGM units can accommodate greater flow rates and

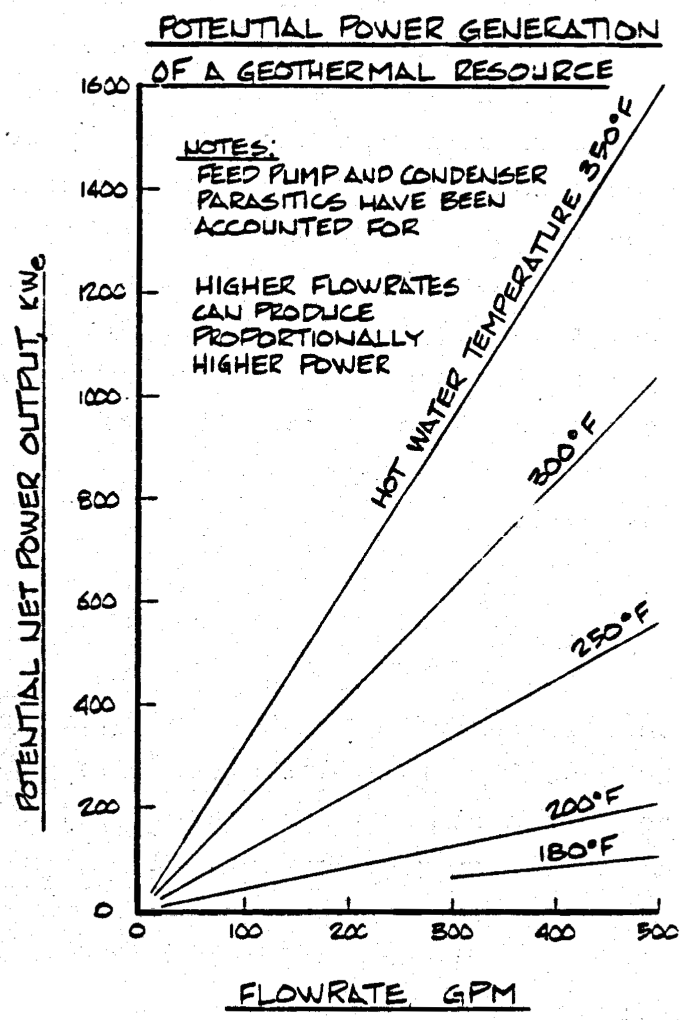


FIGURE 2

produce proportionately larger output powers. The output power from two-phase water-steam or steam alone is much greater than the curves shown for liquid.

COMPONENT DESCRIPTION

The preheater and evaporator are tube-and-shell type heat exchangers. The preheater and evaporator are constructed in accordance with the ASME pressure vessel code and meet the standards of the Tubular Exchanger Manufacturers Association (TEMA).

The standard working fluid condenser is known as an "evaporative condenser". This type of condenser combines the functions of a condenser and cooling tower into one integrated package. The PGM working fluid is condensed inside the condenser tubes. Water is sprayed over the outside of the tubes to absorb the heat from the condensing fluid. Air is blown over the water and a portion of the water is evaporated. This process maintains a nearly constant tube temperature throughout the condenser. The power required for the condenser pumps and fans is supplied by the PGM. The water flow rate in the evaporative condenser is much less than required for a tube and shell condenser supplied by a cooling tower or cooling pond and large water pumps with their higher power usage are not required. This approach is used to improve the efficiency of the PGM and since it is less costly in most cases, it improves the return on investment as well.

ROTATING MACHINERY

The rotating machinery includes the turbine, generator and the feed pump. The turbine is a high efficiency, single stage design, direct-coupled to the 3600 rpm generator. This eliminates the requirement for a speed-reducing gearbox. The feed pump is mechanically driven by the turbine output shaft. This approach eliminates the number of energy conversions and improves overall efficiency. The feed pump drive is designed to provide high efficiency and low maintenance.

TURBINE

The turbine blading and nozzle design is based on the results of aerospace research programs. The blading uses a highly refined contour and a manufacturing process that provides extremely good surface finishes. Turbine efficiencies of 80% in a single stage have been achieved.

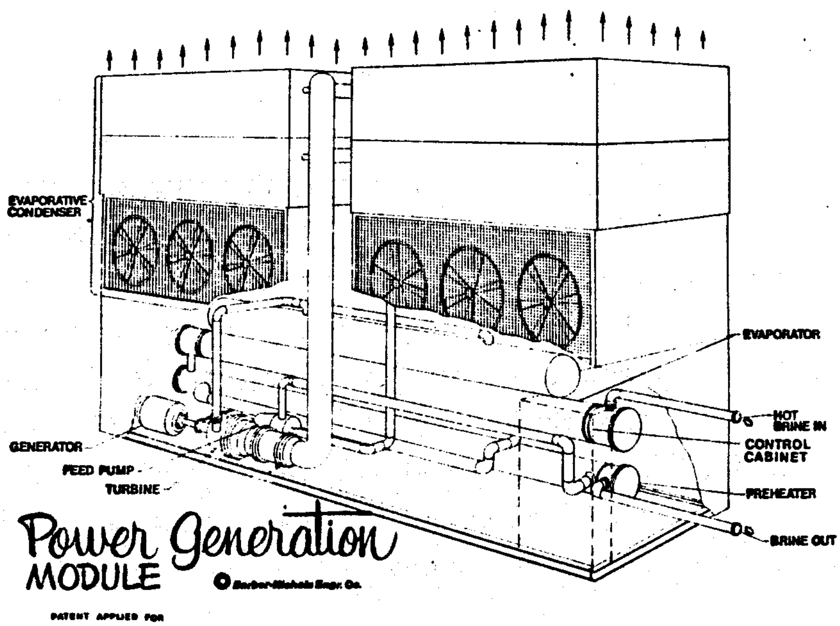


FIGURE 3

FEED PUMP

The feed pump is a centrifugal-type pump and is mechanically driven by the turbine output shaft to eliminate the losses associated with a motor drive. The pump is specially selected and installed to provide adequate net positive suction head (NPSH) for reliable operation.

GENERATOR

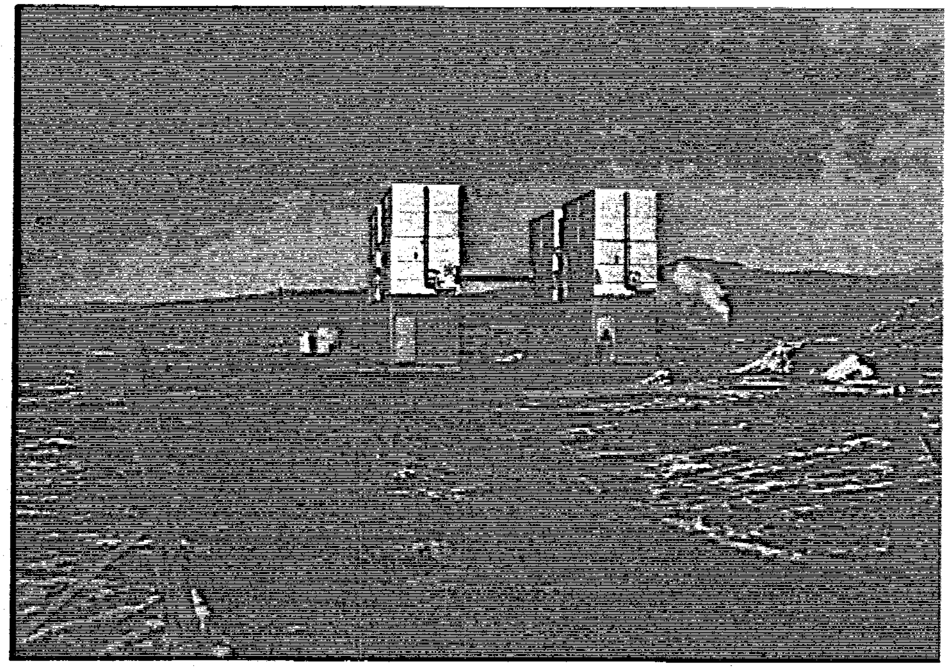
The induction or synchronous generator is directly connected to the turbine by a drive shaft. Standard electrical output is 480 volt, 3-phase, 60 Hertz. The electrical output of the PGM is compatible with the electric utility.

CONTROLS AND SAFETY EQUIPMENT

The PGM controls provide for automatic system startup and operation. The PGM operation is self-monitored and, in the event that selected operating parameters are exceeded, the module will automatically shut down. Automatic telephone notification of a problem to an operator is provided. A full-time operating staff is not required. When the condition that caused a shutdown is cleared, the unit will automatically restart and properly reconnect to the power line.

PGM PACKAGE

The rotating equipment, controls, preheater and evaporator are packaged in a structural steel frame. The structure also supports the evaporative condensers which are located above the other equipment. The structure is enclosed within a lockable, weatherproof, metal enclosure to provide environment protection and security. The module size is approximately 40 feet long, 23 feet high and 10 feet wide, and is arranged as shown in Figure 3. The packaging facilitates easy installation on a simple concrete slab and transportability of the module by truck.



In summary, the PGM utilizes a simple, subcritical Rankine cycle that provides high conversion efficiencies with very reliable operation. The operational controls require only a single modulating control valve that maintains the proper working fluid inventory in the boiler. Figure 4 illustrates two PGM's that are installed on one wellhead. These units have been in operation for several months and are operating with capacity factors in the high 90% range.

RADIAL INFLOW TURBINES
ROBIN DAKIN
ROTOFLOW CORPORATION

Introduction

This paper describes some of the many features on the modern turbo-expanders which makes this type of turbine suitable for the geothermal industry.

Expanders rated at more than 15,000 HP are already existing, having been developed from 10 HP - a 2000-fold scaleup.

These large expanders routinely give design efficiency in the 85 to 87 percent range.

Why is the radial inflow turbine important to the geothermal industry.

1. It can handle almost any amount of liquid condensing in the turbine itself. This reduces the amount of superheat or eliminates it and for a given resource temperature, produces the maximum power from the resource.

2. Because this turbine can handle a very large volume ratio, a single stage can most often be used. This has the further advantage that varying flows can be more efficiently handled without "stage" mismatch.

3. As there is only a single stage turbine, complex development is eliminated and dangers of stage interaction are done away with. This applies particularly to vibration.

4. The variable nozzle philosophy eliminates wasteful power loss of throttling valves, and permits more rapid response from the machine than if one had to work with a large inertia valve in the turbine inlet.

5. It is available as a custom matched design in the time frame normally allotted to "off the shelf" power machinery.

6. Closed loop isobutane systems involve rapid boiling and this results in quite extensive carryover of solids. These in turn can cause severe erosion of components, but the radial inflow turbine can be built to handle this. The passage of particles through the turbine is essentially parallel to the blading with negligible impingement. Nozzles can be treated to resist the erosion of solid particles. Simple centrifugal treatment of the condensate should remove whatever particles are causing trouble, but on a startup it is difficult to achieve 100% cleanliness.

7. A simple overhung turbine can be made "stiff" i.e. one that is run below its first shaft or bearing critical speed. This in turn greatly reduces wear and tear in the event of any accidental or unforeseen damage to a turbine which in turn greatly reduces repair times. It also permits use of non-contacting seals.

8. Easily adaptable to other conditions should a field deplete or be moved to another location.

To expand on these points:

1. <u>Capability of handling condensation</u>

About 40 years ago Dr. J. S. Swearingen built and operated the first natural gas cryogenic expansion turbine in the United States. From cryogenics to warm binary turbines is no big step and has been done now for many years.

Fig. 1 shows what happens when condensation takes place in a radial inflow turbine. The droplets "float" through the turbine and do not impinge on the blading.

The discharge velocities are also much less than with an axial machine, a characteristic which results in inherently higher efficiency (see Fig. 2).

2. <u>Ability to handle a wide range of Flow</u>

The single stage turbine has another unique characteristic in that it can handle a varying flow in a somewhat unusual manner.

At part power, the nozzle throttles the flow more than at design, leaving a little less for the turbine. At the turbine discharge the outer periphery runs full and at close to design conditions, but the pressure drop is not quite sufficient to bring the gas to the inner diameter: the latter results in some recirculation and an ideal dead zone.

It is this characteristic in conjunction with the variable nozzles that give the radial inflow turbine such a flat operating characteristic with volume flow. See Fig. 3.

One of the principal effects on the turbine occurs because of varying condensing conditions. We can make the most use of the turbine in the winter months by allowing the backpressure to fall and obtain more power. The resulting enthalpy increase in an axial turbine tends to mismatch the stages. In the radial inflow turbine the relative velocity at entry to the turbine is small so changes are far less significant than with for instance an impulse type of unit with high relative velocity. Commonly we have to deal with as much as a 30% change in enthalpy relative to design. The effect on efficiency is shown in Fig. 4.

3. Simple Machine

A radial inflow turbine wheel has to be designed within criteria of weight, performance, vibrational characteristics and be able to handle whatever rotational stresses arise as well as gas bending loads. It is always quicker to design one of something than several, so a single stage radial inflow turbine as well as being inherently more efficient is quicker to design and develop.

Where each new application has similarities to those already proven, it sometimes occurs that the combinations are unique. As an example, in the case of one closed loop isobutane cycle, the combination of a high molecular weight with relatively high pressure ratios 11.3 to 1 resulted in excitation by some nozzle harmonics that had not been previously seen. Solutions that had shown years of satisfactory service were not adequate for the combination of very high pressure ratio and high molecular weight and exact speed that this machine gave. Establishing a solution once the problem was realised was straight forward and took no more than week. Realizing we had a brand new phenomena took longer and was complicated by other factors such as contamination.

With a multiple stage machine, handling of new phenomena is far more difficult and particularly with the axial machine, there is less scope for adjustment. The multi-million dollar investment in the aircraft gas turbine industry is witness to this.

4. Variable Geometry

There is qnly so much energy available; to waste it with a throttling device upstream of the turbine defeats the purpose, also because volume flows can be very large, the size of such a valve is large and its mass and inertia can preclude sensitive control. The radial inflow turbine is controlled by a single set of variable nozzles of low inertia where the throttling effect is converted to kinetic energy which is directly recoverable in the turbine. Smaller sizes are easily operated with conventional actuation and the nozzles are pressure clamped to avoid the leakage build up that plagued other designs that operated with any sort of clearance.

Larger sizes are more tolerant to leakage and more sophisticated designs are in use for instance with the 50 inch turbines operating with the U.S. Air Force. See Fig. 5.

5. Custom Availability

Because our philosophy has been to custom match each turbine to suit the conditions, we have become very good at it. The time taken to put a turbine design together with the use of computers is now small compared with the routine actions of getting the raw material castings or forging and putting these parts through a machine shop. Typically the controlling items in a job are not those items we specifically manufacture, but purchased items such as generators and gearboxes. Small machines have been built in as little as three months, larger units typically will take up most of a year. This data is necessary for those attempting to plan potential geothermal plants.

6. Ability to handle Solids

Over many years, we have experienced the effects of pipe lines that have not been as clean as the optimists would have them and we have had to evolve methods of preventing dirt erosion damage. Fig. 6. shows a simple approach to preventing dirt scouring that has proven effective over many years. It prevents a little closed loop of dirt and gas recirculating around the seal that can cause rapid wear, loss of performance and an upset to thrust balance.

Many would consider that a closed loop Rankine cycle system is naturally cleaner than a pipeline. However, we have seen by far our worst erosion in closed loop systems where there is no clean up and a dirt source has been introduced. In one case we had an instance of a heat exchanger in storage that was supposedly clean but contained a pound or two of iron oxide. Hard nozzles and adjusting rings were worn almost through.. Once the source was cleaned up, the problem ceased but in a very large loop such as a geothermal Rankine cycle, there are several sources of contamination.

(a) Site contamination: Often sites are in remote areas and in the pace of construction, sand, gravel and weld scale or beads are easily introduced.

(b) Manufactured items: heat exchangers, casings and piping are rarely corrosion free and machining chips or casting sand can be overlooked and will break loose with a little thermal cycling.

(c) The working fluid: having a high density, the working fluid can carry particles and because it is delivered as a liquid a considerable quantity of contaminants can be introduced from this source.

(d) Any damage of failure item: - if something should break and get into the system, then as it breaks up these particles can go around and add to the erosion burden.

The high boiling rates prevent too much settling of contaminants and unless physically removed from the system, these contaminants will greatly reduce the service life of the turbine. The removal is most easily accomplished at the condensate stage, where a centrifugal filter will handle the bulk of fines. A mesh pad over the boiler will also eliminate a lot of carryover.

Specially designed inlet screens are available that will take a high pressure drop without bursting and catch any large rocks or articles entrained in the loop - I well recall seeing a cigar in its aluminum tube floating out of one lube system many years ago. Strangely, no one claimed it.

Hard coatings such as Tungsten Carbide have been used very successfully in systems where particle separation is impossible to eliminate completely but are a last resort and normally not necessary.

7. Why a "Stiff" Shaft is Better

The concept of a "stiff" shaft and bearing construction is not new; the challenge has been how to meet it with modern high tip speed turbines. The prime advantage has been excellent shaft control with minimal secondary damage in the event of out of balance. Blading can get damaged for a variety of reasons: even ice in a low temperature application or under some start up condition liquid might enter the turbine in slugs.

A flexible shaft runs above its critical speed and out of balance results in a shift of center of gravity and consequent heavy seal wear. Another quite serious problem could develop if the isobutane or other working fluid were to dilute the lube oil. Then critical speed with the flexible shaft system could easily enter the running range with severe consequence. Change in environmental conditions can also be sever resulting in viscosity changes of 10 to 1 from start up to running. This is no problem for a stiff shaft/stiff bearing design which is not difficult to achieve with the radial inflow single overhung turbine.

The use of a stiff shaft has another advantage, it allows the use of a labyrinth non-contacting seal (Fig. 7). Eventually all contacting seals will wear and they can be very expensive to replace. Labyrinth seals have run as long as 20 years with no attention.

A non-contacting shaft labyrinth seal allows a small amount of gas to contact seal oil. The oil is then heated to drive off dissolved gas and returned to the lube system. There is no need then for a separate seal oil system.

8. Adaptable to other conditions

Fields do change and when they do the conditions for which the expander was designed also change. A new wheel is often all that is required to exactly match the new conditions. A 1% improvement in efficiency on a 5 MW machine can result in $42,000 per year increased profitability.

Similarly if financial conditions are more attractive in another location, the turbine can be reoptimized simply and easily to suit those conditions.

Summarizing

The radial inflow turbine presents the best state of the art solution to maximize return from any geothermal site that is suitable for binary operation.

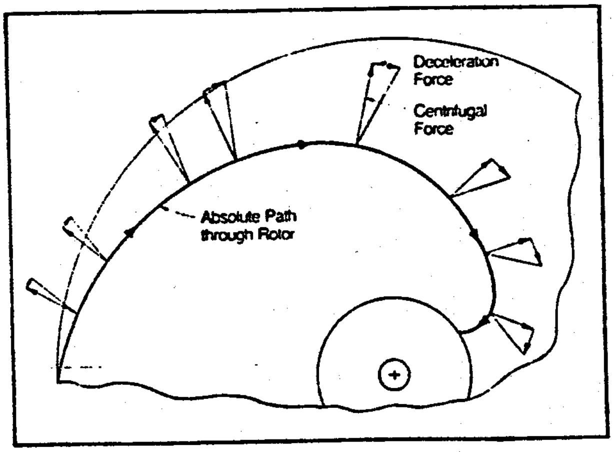


FIGURE 1
CONDENSING EXPANDER ROTOR

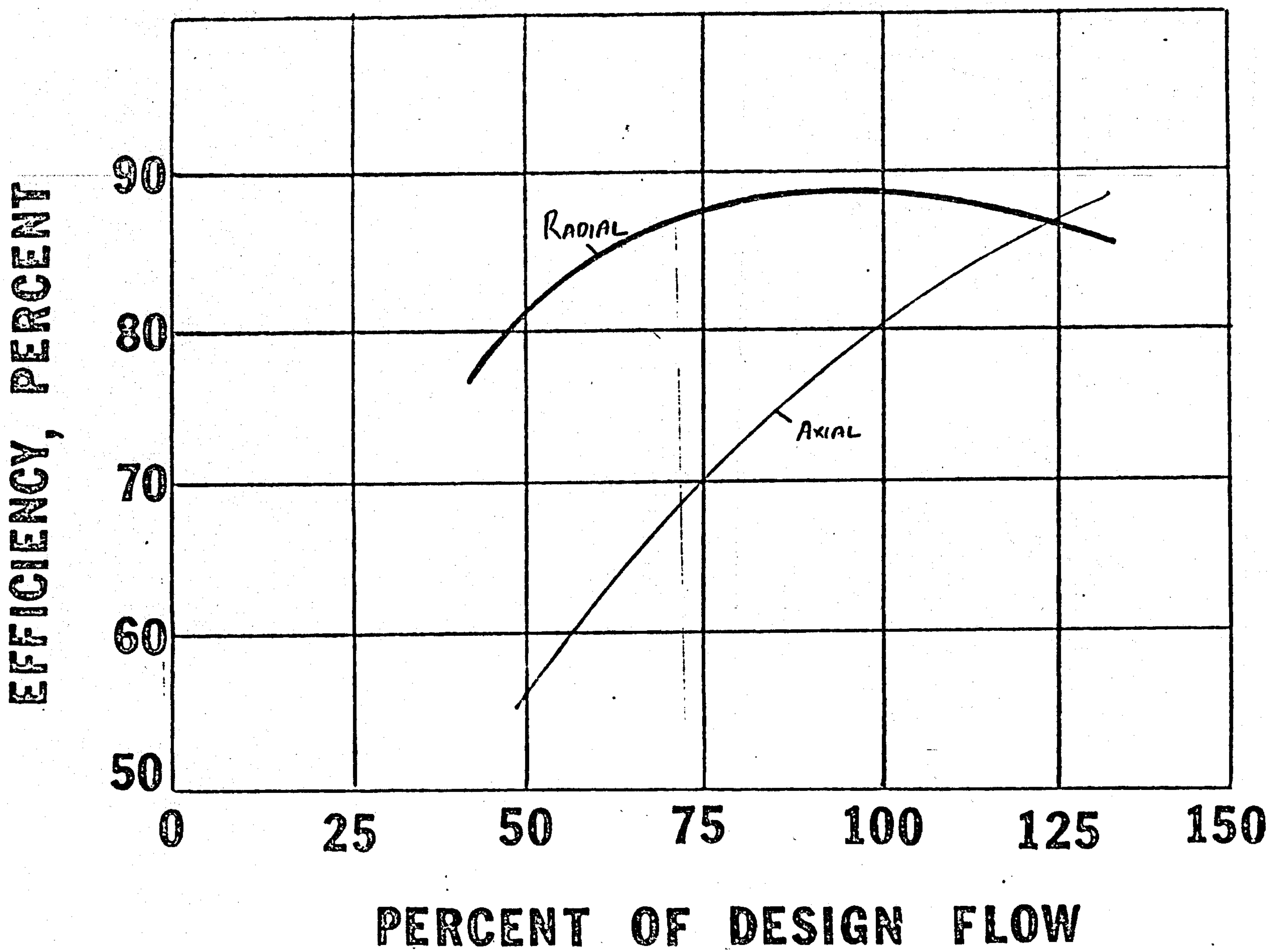

EFFICIENCY, PERCENT
90
80
70
60
50
RADIAL
AXIAL
0
25
50
75
100
125
150
PERCENT OF DESIGN FLOW

FIGURE 2

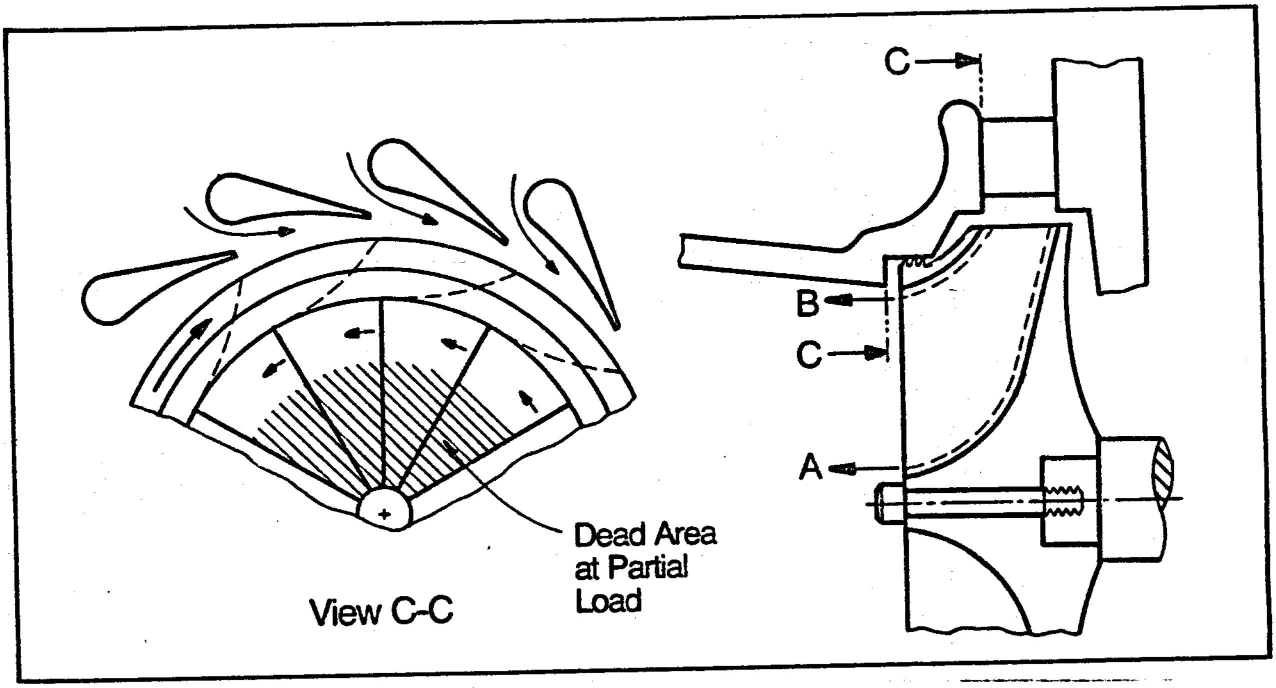
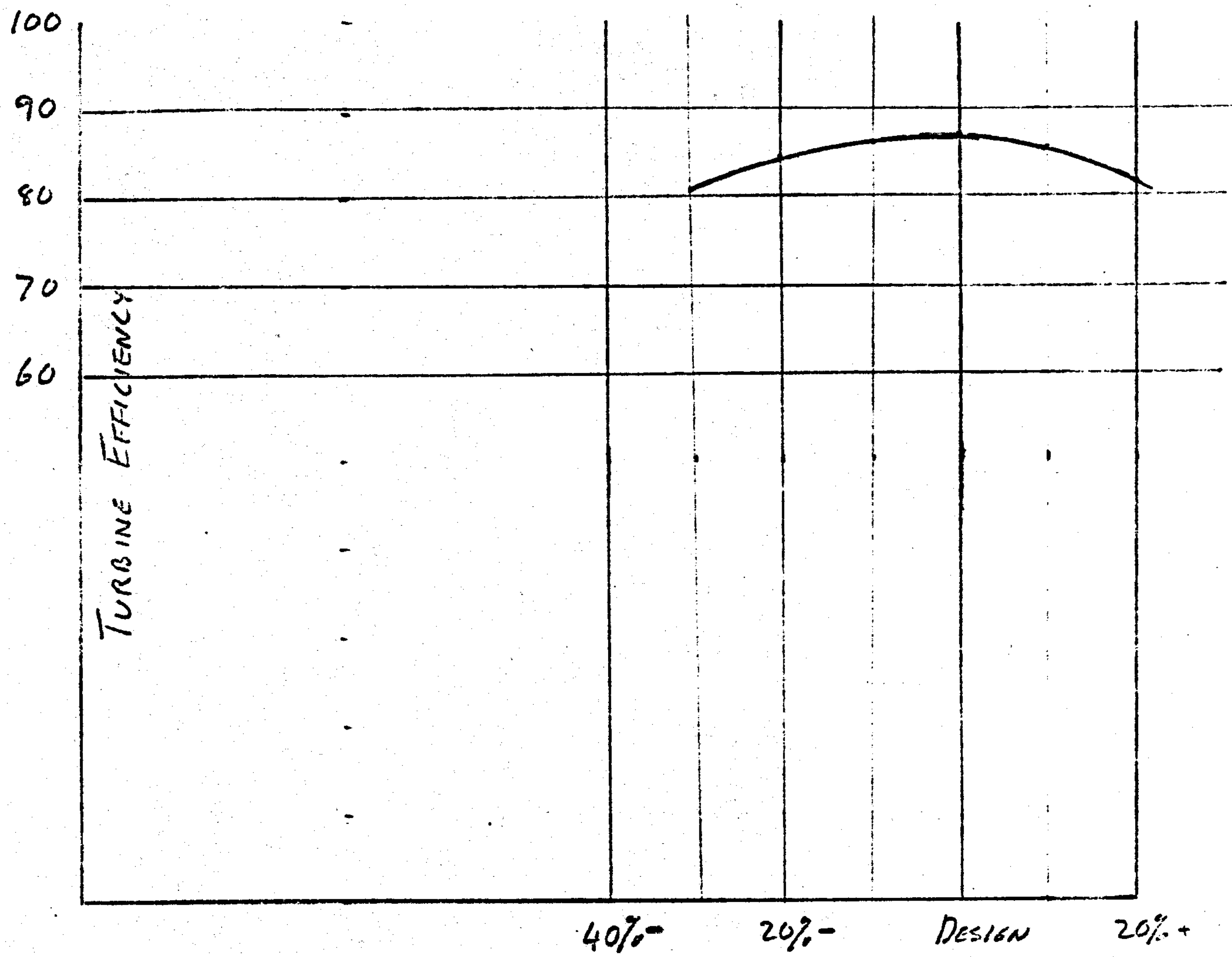
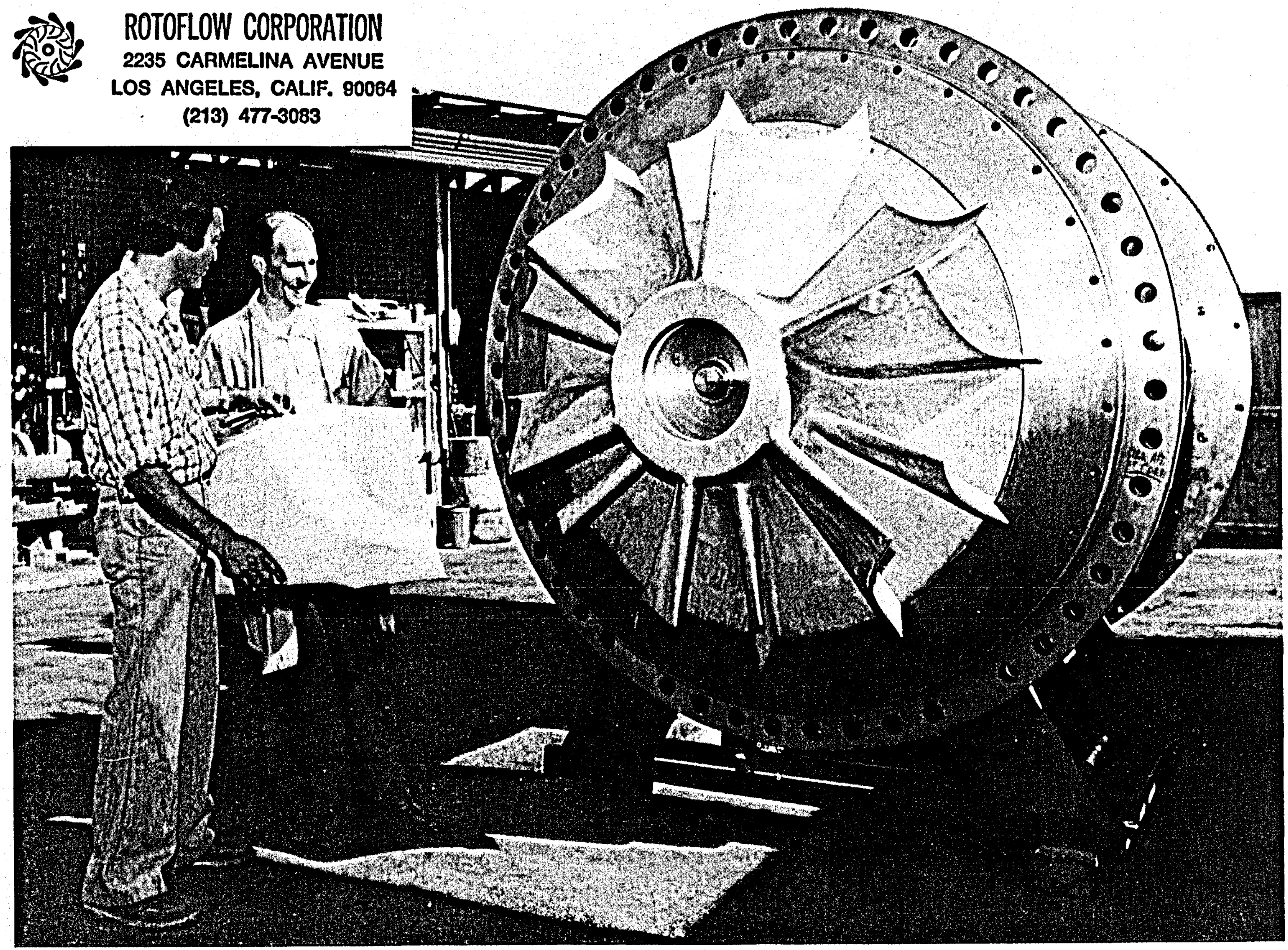


FIG. 3
OPERATION AT LOW FLOW



EFFICIENCY CHANGE WITH ENTHALPY
FIG. 4

ROTOFLOW CORPORATION
2235 CARMELINA AVENUE
LOS ANGELES, CALIF. 90064
(213) 477-3083



Mechanical center section of Rotoflow refrigeration turbine system can be removed intact from main unit. Compressor impeller above has 55-inch diameter.

FIG. 5

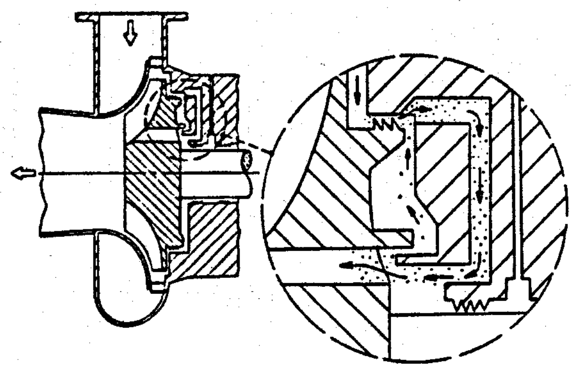
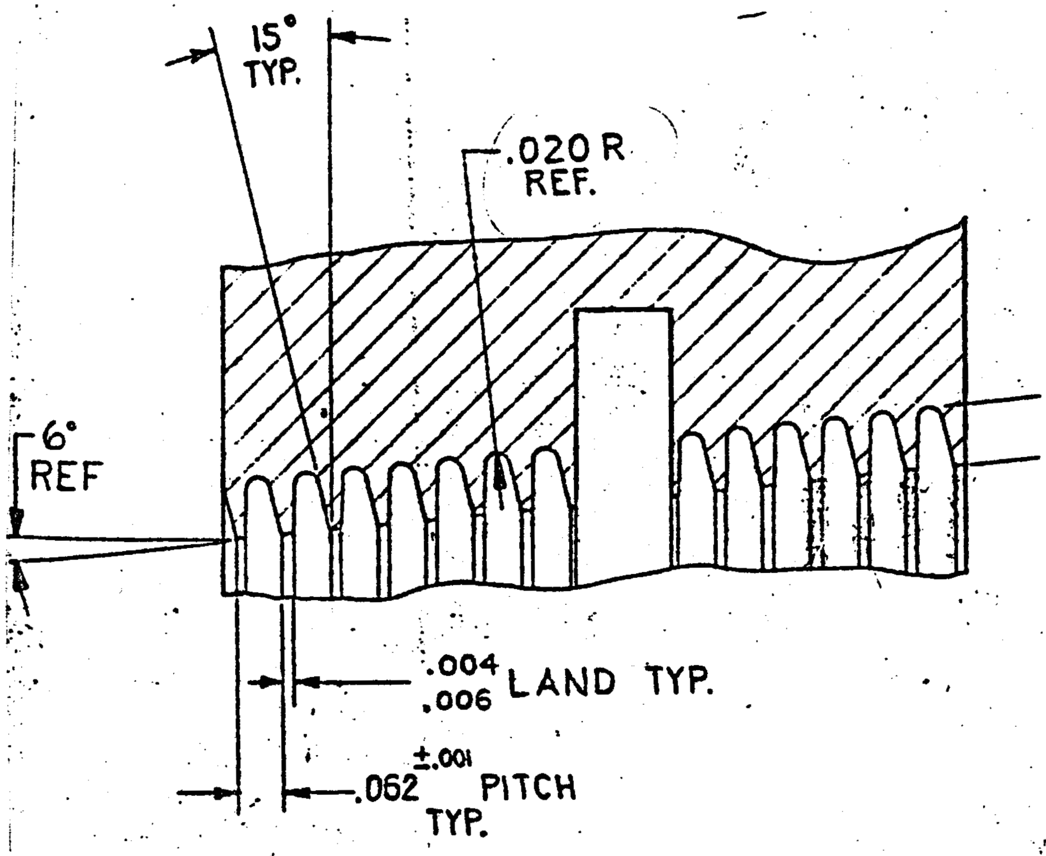


FIGURE 6.
ROTOFLOW'S DUST-FREE DESIGN



LABYRINTH SEAL NON CONTACTING
FIG. 7

HYBRID POWER SYSTEM FOR A GEOPRESSURED WELL

Evan Hughes
Electric Power Research Institute
P.O. Box 10412, Palo Alto, CA 94303, (415)855-2179

OBJECTIVES

The Electric Power Research Institute (EPRI) is conducting a test of a combustion-geothermal hybrid power system in order to evaluate the performance, reliability and other operational aspects of a concept that can produce 15% more electric power from a given combination of combustion fuel and geothermal fluid than would be produced by separate combustion and geothermal power generation facilities. By performing this test in cooperation with the U. S. Department of Energy (DOE) at one of the DOE geopressured wells, EPRI will also continue its evaluation of the potential for utilization of geopressured resources in electric power production.

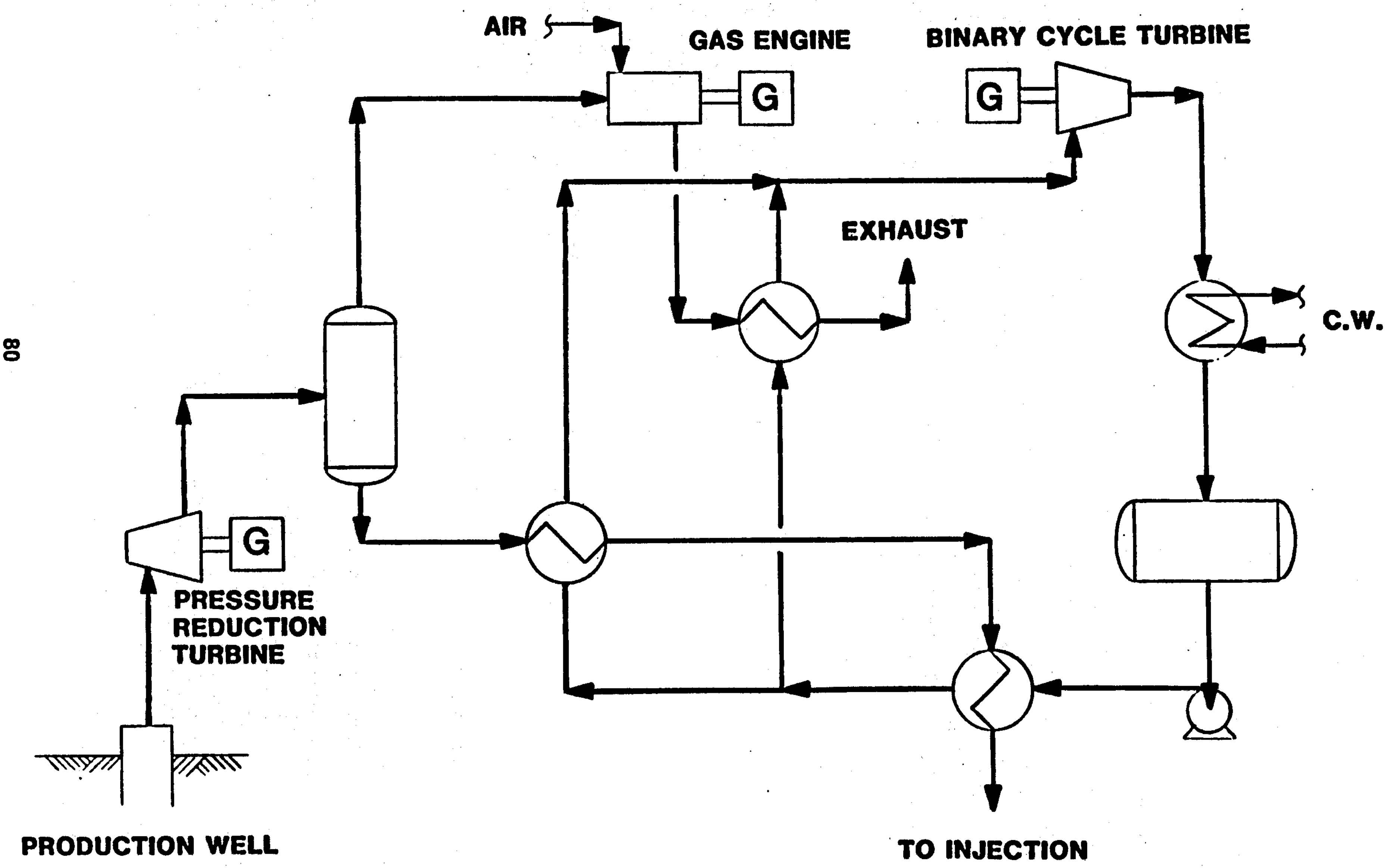
CONCEPT

Figure 1 illustrates the concept as it will be tested in the geopressured application. Electricity will be generated from three sources of energy: (1) 650 kWe from methane dissolved in the fluid, (2) 540 kWe from heat contained in both the geothermal brine and the exhaust gases from combustion of the methane, and (3) 290 kWe from the hydraulic potential in the flow of high pressure brine from the geopressured reservoir. These power levels in the test system are based on a well flow rate of 20,000 barrels/day through the hydraulic turbine and 10,000 barrels/day of separated brine through the heat exchanger in the 540-kWe binary power system that constitutes the bottoming cycle of the hybrid power system. Gas flow is assumed to be 19 standard cubic feet per barrel of brine derived from half of the 20,000 barrels/day flow of brine into the gas separator.

DESIGN AND PROCUREMENT

EPRI has awarded a contract to The Ben Holt Company to design and procure the binary power system and parts of the balance of the complete hybrid system shown in Figure 1. Much of the equipment to be used has been made available to the EPRI project by DOE. This is equipment from the 500 kWe direct contact heat exchanger power system test performed at East Mesa from 1981 through 1983. Under contract to EPRI, Holt has developed a design to integrate the East Mesa equipment into the complete system shown in Figure 1.

HYBRID CYCLE FLOW DIAGRAM



GEOPRESSURED HYBRID POWER PLANT PROJECT

PROJECT OBJECTIVES:

- EVALUATE THE COMBUSTION-GEOTHERMAL HYBRID POWER CONVERSION CONCEPT AT THE PLEASANT BAYOU GEOPRESSURED WELL.
- OBTAIN GEOPRESSURED RESERVOIR AND FLUID DATA IN LONG-TERM (3-5 YEARS) FLOW TEST.

PARTICIPANTS:

- EPRI, DOE, WK TECHNOLOGY: COSPONSORS
- EPRI'S CONTRACTORS FOR DESIGN, PROCUREMENT, TESTING
- DOE'S CONTRACTORS FOR INSTALLATION, OPERATION AND TESTING

EEH

BEOWAWE 16MW GEOTHERMAL POWER PLANT PROJECT

CHEVRON GEOTHERMAL COMPANY/CRESCENT VALLEY ENERGY CO.

NOVEMBER 6, 1985

L.T. Elliott

Chevron Geothermal Co. of California

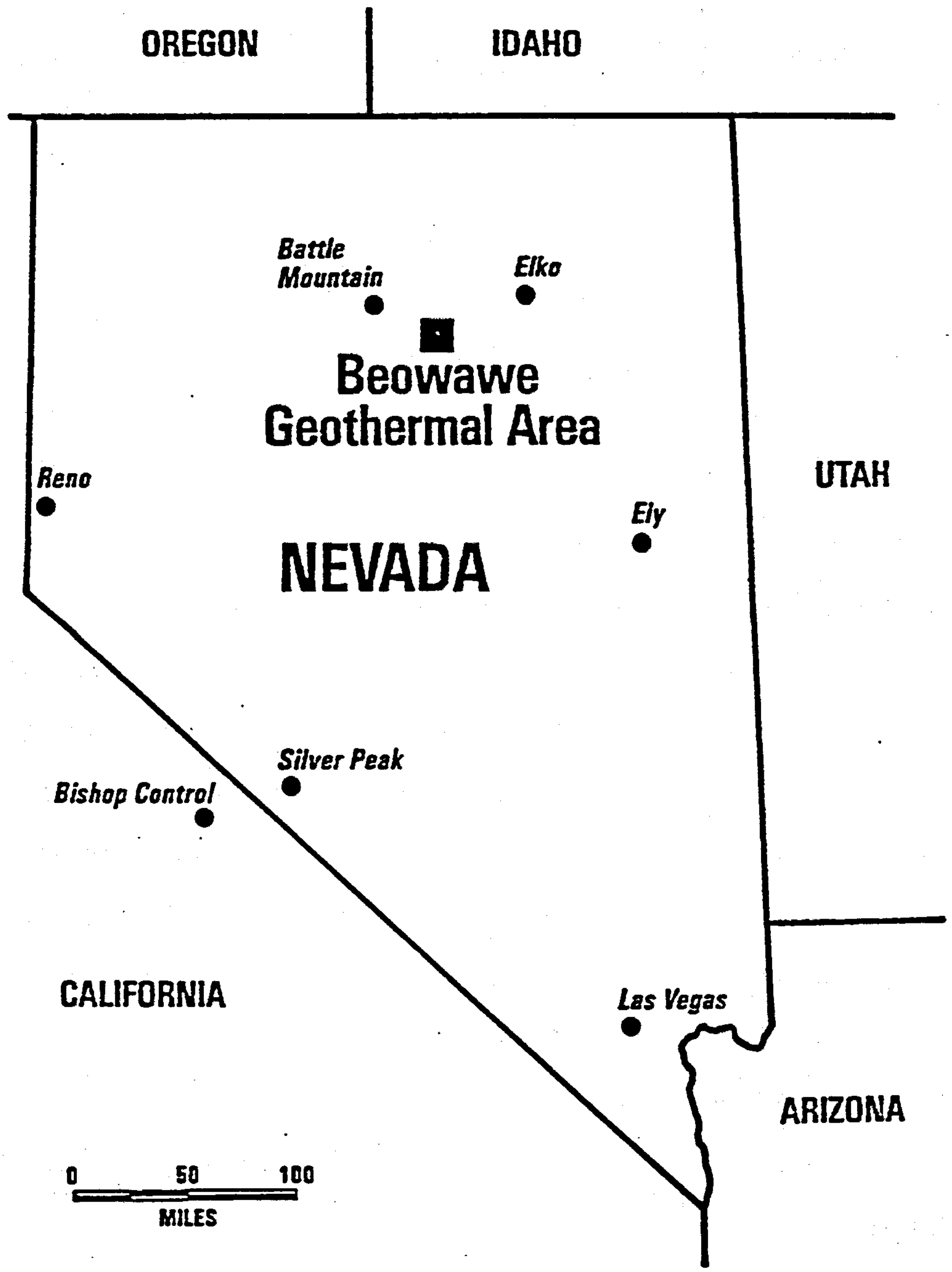
San Francisco, CA

ABSTRACT

Chevron Geothermal Company of California and Crescent Valley Energy Company, a subsidiary of Rosemead, California based Southern California Edison Company (SCE), have entered into a general partnership to develop the Beowawe Known Geothermal Resource Area located near Beowawe, Nevada. The resource, which has been developed by Chevron in recent years, will provide geothermal heat in the form of hot water and steam to a dual flash plant which is being built by Crescent Valley Energy Company. The power plant will generate 16.6 MW Gross of electrical energy which will be sold to Southern California Edison Co. The project is currently in the final stages of construction and plant start-up is scheduled for mid-December.

INTRODUCTION

The Beowawe Known Geothermal Resource Area is located in the north-central portion of Nevada, a few miles south of Interstate Highway 80 and six miles west of the small town of Beowawe. See Figure 1. Geologically, the field is in the Basin and Range province at the



PROJECT LOCATION

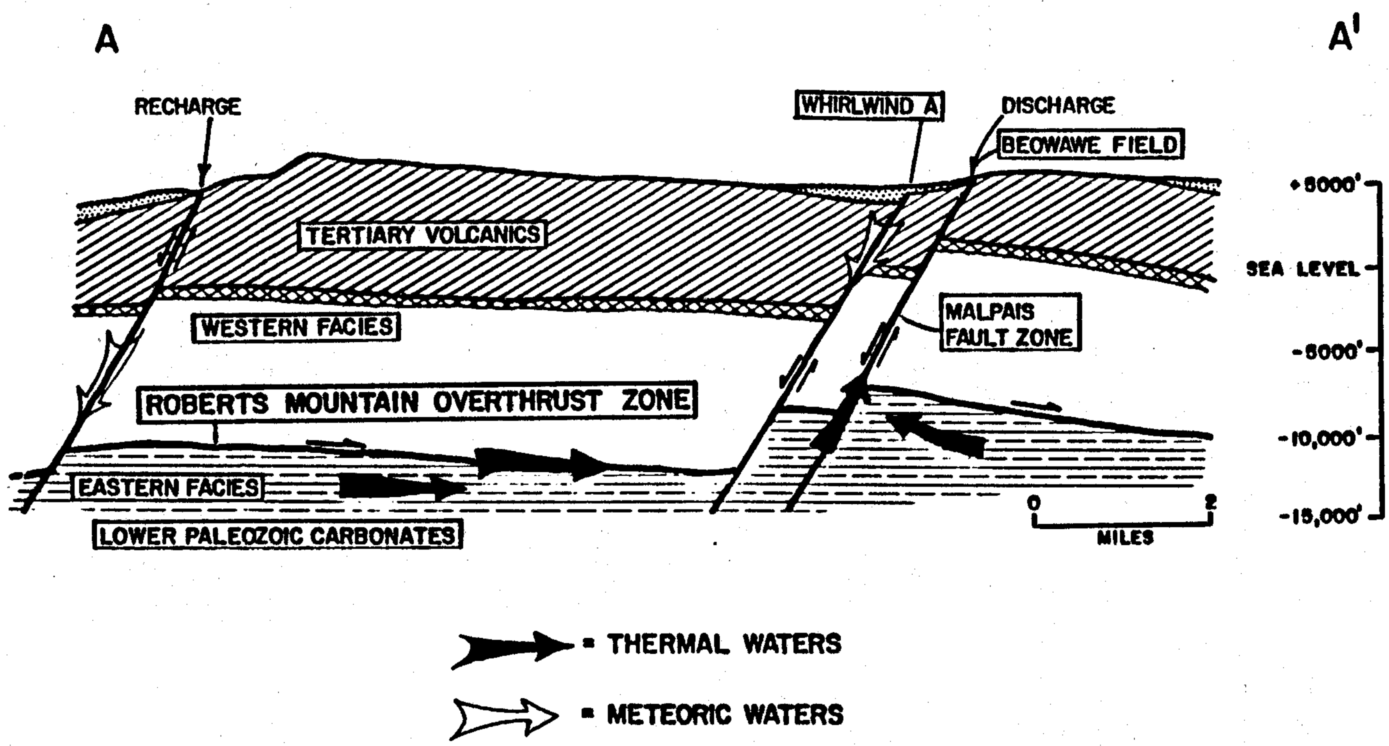
FIGURE 1

boundary of a volcanic plateau which lies to the south and the downfaulted Whirlwind Valley to the north. The geologic setting of this area has been extensively studied and documented in the literature and no attempt will be made here to review that information in detail. In summary, the key elements of the geologic model of the Beowawe Area are a deep reservoir in lower Paleozoic carbonates at 15-20,000 feet which is regionally charged by meteroric waters. This reservoir feeds an inclined thermal plume within the Malpais Fault Zone that is tapped by the production wells. This upward flow of geothermal waters also accounts for the thermal surface manifestations in the area. A simplified drawing of this model is shown in Figure 2.

Chevron Geothermal Company of California and Crescent Valley Energy Company have formed a general partnership for the purpose of developing, owning and operating the initial power plant project on the Beowawe resource. The partnership is called the Beowawe Geothermal Power Company (BGPC). The project consists of installing field production and injection facilities and a dual flash power plant to generate 16.6 MW Gross (15.1 MW Net) of electrical energy from the geothermal heat produced at the Beowawe resource. Power from the project will be transmitted via Sierra Pacific Power Co. (SPPCo) transmission lines to Southern California Edison's transmission system where it will be sold under a power sales contract with SCE.

PROJECT DEVELOPMENT HISTORY

The Beowawe area has been well known for the geysers, fumeroles, and boiling springs that have existed there for many years. These surface



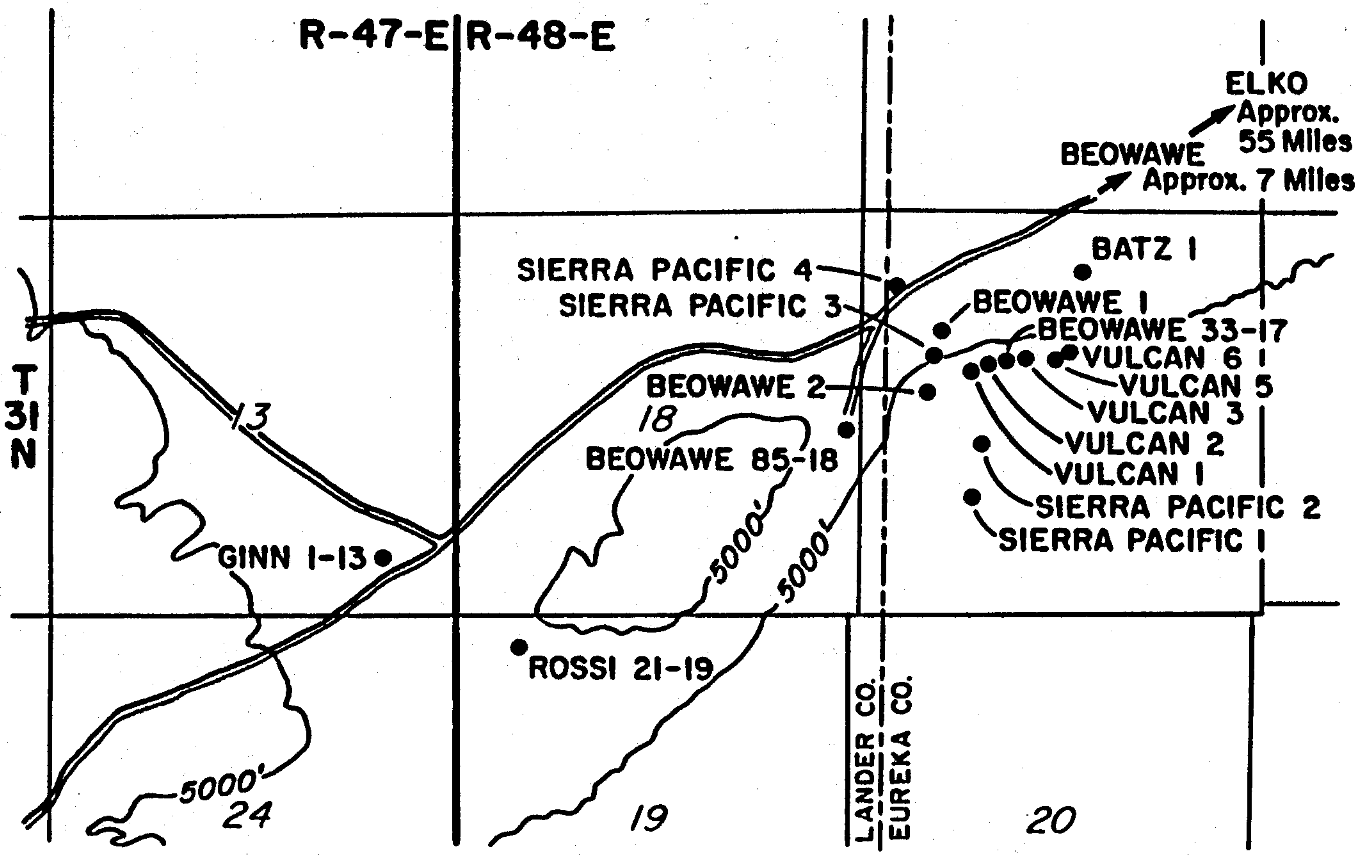
GEOLOGIC CROSS SECTION
REGIONAL CONCEPTUAL MODEL

FIGURE
2

manifestations led Magma Power Co. and Sierra Pacific Power Co. to drill eleven shallow wells between 1959 and 1965 to evaluate the potential for geothermal development. Chevron acquired the leases for the Beowawe area in 1973-1975 and began extensive exploratory work of the area. Chevron drilled its first well, the Ginn 1-13, in 1974 to a depth of 9600 ft. and has since drilled three additional wells in the area to further define the resource. See Figure 3.

Based on the geologic evaluations and well testing performed by Chevron, a geologic model and development plan were defined. An initial power plant development project was proposed by Chevron to the Nornev group of five utilities for a 10MW binary plant utilizing the heat in fluid produced from wells located in the sinter terrace portion of the field. This is the area where the surface manifestations have occured and most of the evaluation wells have been drilled. Negotiations on this proposal continued for several years; however, the changing economic climate in the early 1980's caused several of the utilities in the Nornev group to withdraw from the project and it became necessary to suspend plans for the development.

Despite the economic climate and failure of the Nornev project Chevron was determined to proceed with field development. Chevron retested the Ginn 1-13 well and noticed significant improvement in the well's productivity over that seen in earlier testing such that a development in that area became economic. Geologic and well testing data indicated that the fault zone feeding the Ginn 1-13 well could be tapped with one additional well and that sufficient fluid could be produced to feed a



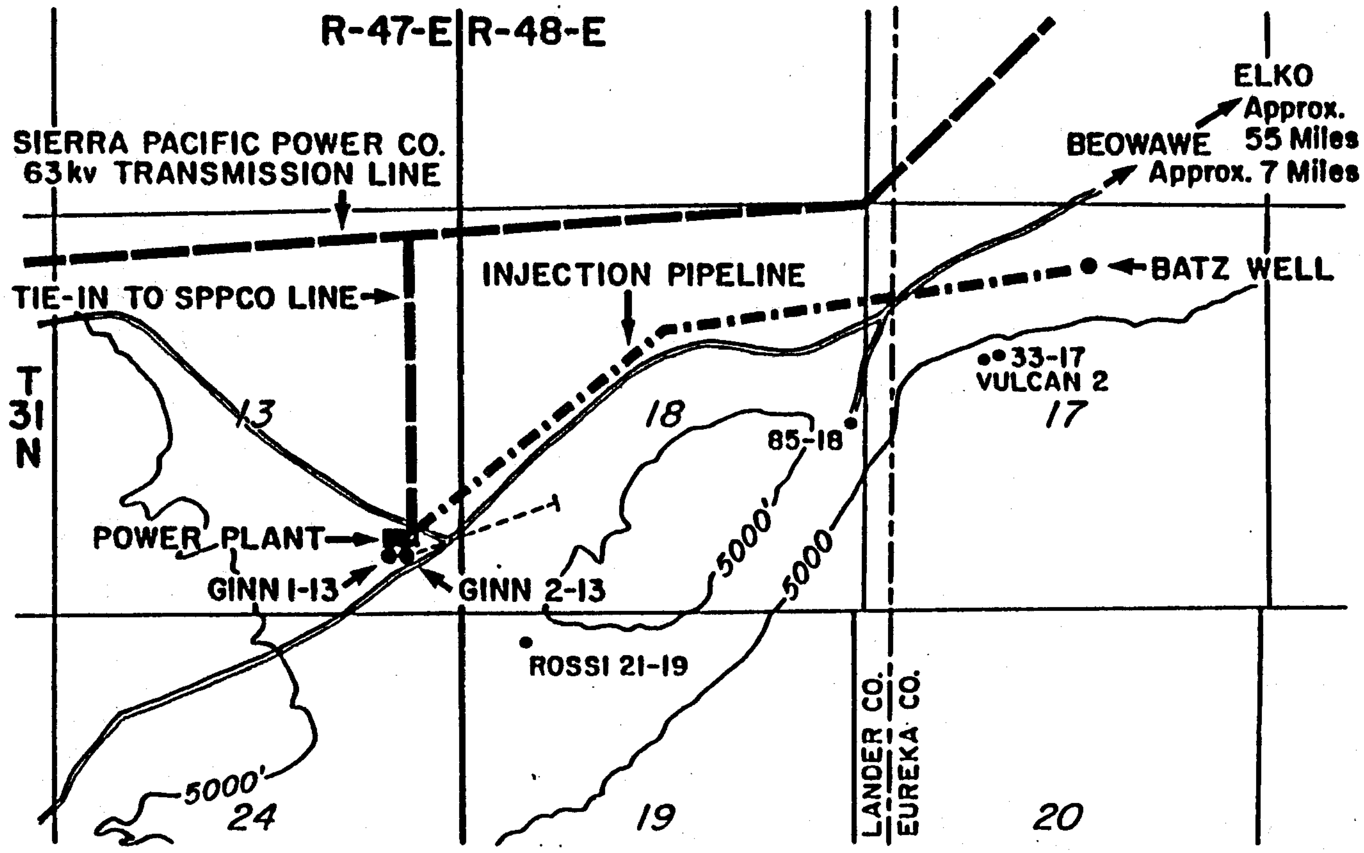
BEOWAWE AREA - WELL LOCATIONS

FIGURE 3

15MW (net) power plant. The project scope was then developed and operational and process parameters defined. Quotation requests for the supply of a complete power plant package were prepared and issued based on the expected production rates and fluid temperatures from the two wells. Based on the responses, an order was placed with Mitsubishi Heavy Industries (MHI) in late 1984 to provide the dual flash power plant equipment. In the mean time, Chevron was having intensive discussions with Crescent Valley Energy Co. (CVEC) which ultimately resulted in the formation of the partnership. Under the partnership agreement CVEC took over responsibility for the construction of the power plant from Chevron.

PROJECT DESCRIPTION

The 16.6MW dual flash power plant design is based on the delivery of 1.254 million pounds per hour of fluid with a bottomhole resource temperature of about 410°F. The geothermal fluid has a TDS of about 1200 ppm and a noncondensible gas content of only a few ppm. The fluid will be delivered to the plant from the two production wells in the two phase flowing mode. At plant delivery conditions the flow stream will contain about 13% steam. The existing Ginn 1-13 well is located about one mile west of the sinter terrace area, and is utilized as one producing well. A second well, the Ginn 2-13, has since been drilled into the producing fault zone and will supply the remainder of the fluid to the plant. Initial flow tests of this second well indicate that the desired production requirements and temperature for the plant can be met. The layout of the field facilities is shown in Figure 4.



BEOWAWE 15MW PROJECT
NEVADA

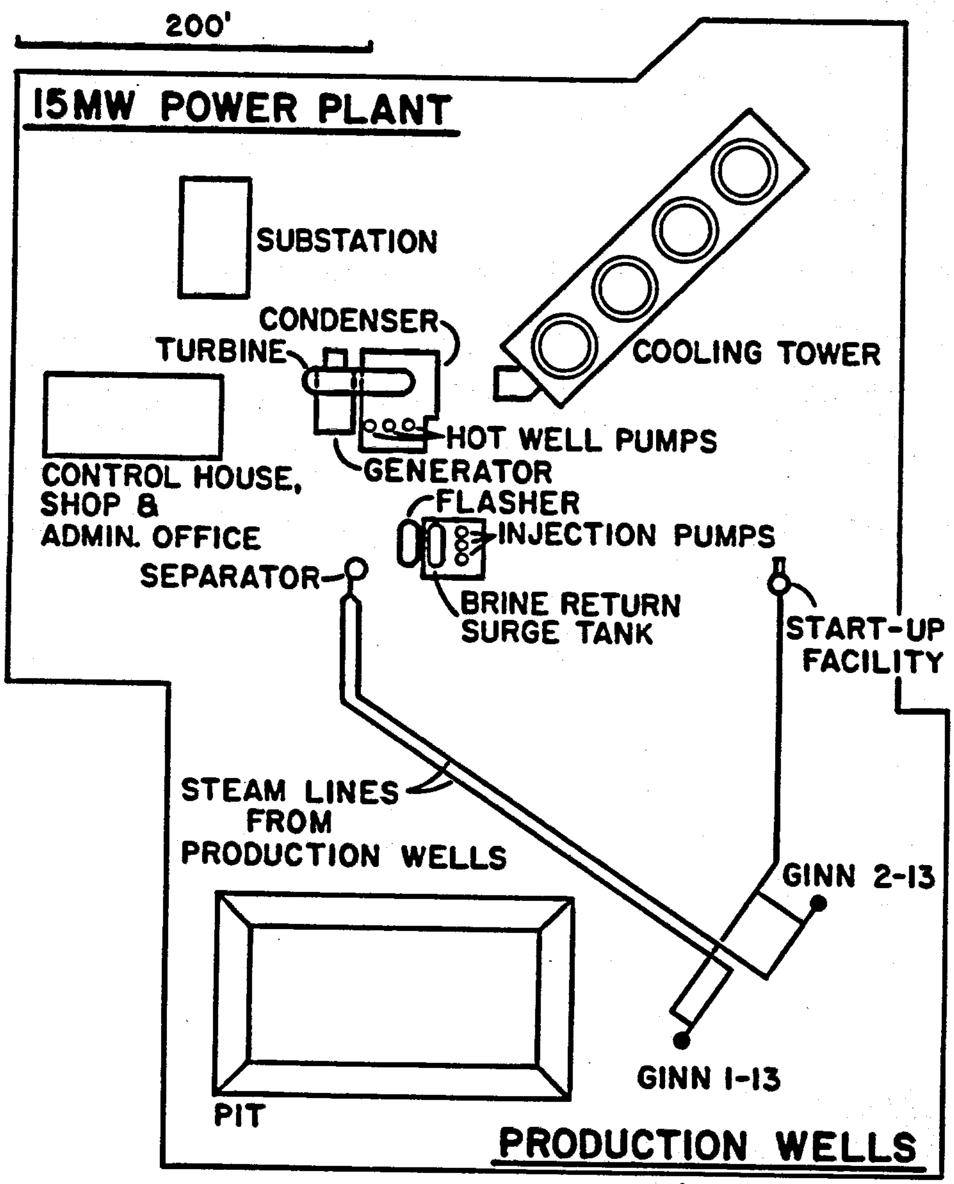
FIGURE 4

The power plant consists of a single train of high and low pressure flash vessels which separate the two phase production stream and feed steam to the double pressure turbine-generator unit. The first stage flash pressure is 64 psia and the second stage pressure is 16 psia. The turbine exhausts at a pressure of 1.25" Hg to a direct contact spray type condensor which utilizes a five cell wet cooling tower. The unflashed geothermal fluid returned from the plant is pressured for injection by pumps at the plant and is transported via a 10" diameter two mile long insulated above ground pipeline to the existing Batz well, which had originally been drilled by Magma in 1975, where it will be injected for disposal. The plot plan for the power plant is shown in Figure 5, and a simplified process flow diagram is shown in Figure 6. The power plant comes complete with all equipment, instrumentation, controls, control house and switchgear. Foundations and site preparation are provided by CVEC. The intertie transmission line from the plant to an existing Sierra Pacific Power Co. 60 KV power line located about one mile from the plant will be constructed and operated by Sierra Pacific.

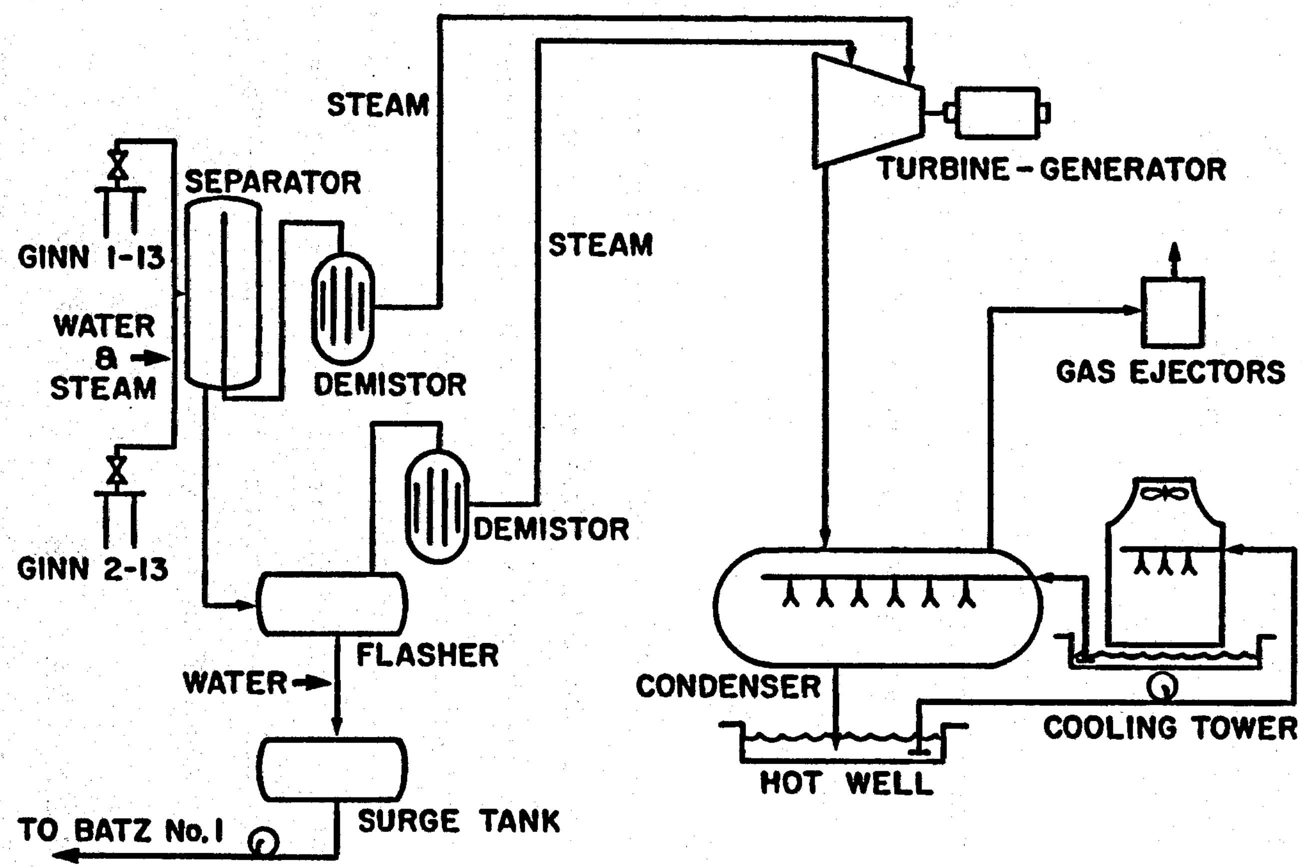
CONTRACTUAL ARRANGEMENTS

Partnership Agreement

The partnership agreement forming the Beowawe Geothermal Power Co. provides for 50/50 ownership of the project facilities. Each of the partners is responsible for contributing certain capital facilities to the project. Chevron is responsible for providing the two production wells, production facilities, injection pipeline, and the injection well. CVEC is responsible for providing the power plant and making the



BEOWAWE FACILITIES SCHEMATIC LAYOUT	FIGURE 5



BEOWAWE POWER PLANT SCHEMATIC

FIGURE 6

arrangements to deliver the power to SCE. Revenues and expenses from the partnership will be shared equally. Chevron has been designated as the operating partner and will be responsible for the day to day operation and maintenance of both the plant and field facilities. Overall operation and management of the project is handled by a partnership management committee.

It is significant to note that this project is being accomplished entirely by two privately financed subsidiaries of a major oil company and a major utility which have formed a partnership to share in the development of a geothermal resource.

Power Sales Agreement

In 1984 Chevron negotiated and executed a power sales contract with Southern California Edison Co. which allows the power generated by the project to be sold at the long term avoided cost available under a Standard Offer No. 4 contract. Chevron is assigning this contract to the partnership. The contract is based on firm capacity, base load operation of the plant. If the plant produces more power than can be transmitted across the intertie transmission line between the SPPCo. and SCE systems the excess power will be sold to SPPCo.

Transmission and Wheeling Contracts

CVEC has assumed responsibility, on behalf of the partnership, for negotiation of the transmission agreements with SPPCo. to provide for delivery of the project power to the SCE system. The arrangements include provisions for phase shifting equipment and additional telecommunications facilities to allow power to flow into the SCE system through the intertie between the two utilities.

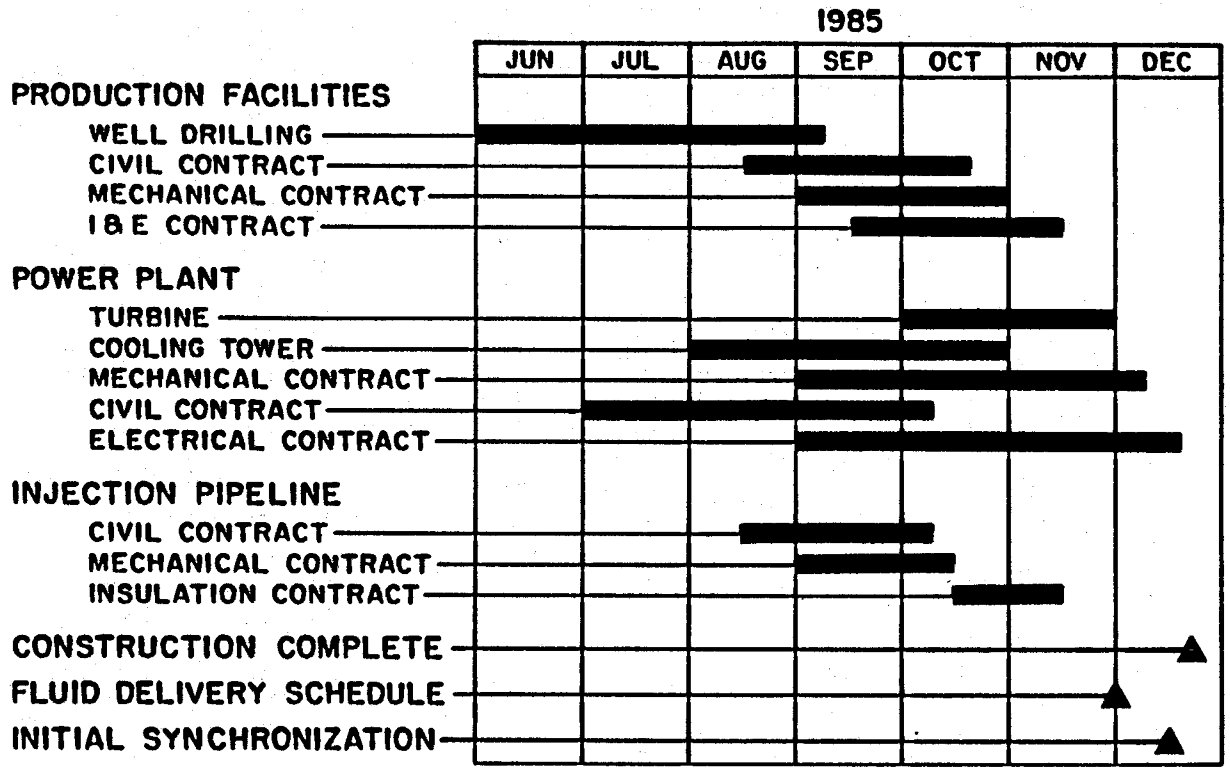
SCHEDULE AND STATUS

Initial site preparation work on the project started in June, 1985 with the construction of the well drilling pad and power plant rough grading. Drilling of the Ginn 2-13 well, the second production well, began in August and was completed in September. The well was drilled to a depth of about 7000 feet. South El Monte based Associated Southern Engineering Co. is responsible for engineering and construction management of the power plant. Construction of the power plant foundations and installation of the plant equipment and facilities started in July and at this point construction is approaching completion. Following installation of the foundations the assembly of the prefabricated packaged power plant equipment has proceeded at a rapid pace.

The current project schedule, Figure 7, calls for start-up procedures to commence later this month leading up to fluid delivery, turbine roll, and initial synchronization by mid-December of this year. The start up schedule is ambitious but at this point appears to be achievable.

SUMMARY

Chevron Geothermal Co. and Crescent Valley Energy Co. have structured a unique relationship in establishing the Beowawe Geothermal Power Company to develop the Beowawe resource. In a period of just over one and one half years, the project scope has been developed, a power plant



POWER PROJECT SCHEDULE
BEOWAWE GEOTHERMAL

FIGURE 7

specified, bid and ordered, designs completed, construction commenced, and a partnership formed utilizing private financing to build and operate a geothermal power plant. The project is currently providing construction jobs in the Northern Nevada area and will continue to provide additional tax revenues and employment for the years to come. The completion and operation of this project is a significant step in our efforts to develop geothermal resources in the State of Nevada.

CASE STUDY
MOTHER EARTH INDUSTRIES' GEOTHERMAL ELECTRIC FACILITY
COVE FORT-SULPHURDALE, UTAH

Any successful Geothermal project requires careful attention to a number of details, any one of which can delay or cripple a proposed Geothermal development. Mother Earth Industries has been extremely fortunate in being the owner of a premier quality resource, which is located in a state with viable power purchasers, and is also blessed with all the other elements necessary to make a successful project. My purpose in this presentation is to outline what Mother Earth Industries (MEI) considers critical success factors for any successful Geothermal project to occur. MEI believes that ten items make up the list of critical success factors.

1. Power Market/Power Sales Contract Potential.
2. Wheeling Agreement.
3. Transmission Line Access.
4. Geothermal Resource Quantity and Quality.
5. Regulatory and Environmental Atmosphere.
6. Reputable Manufacture of Generation Equipment.
7. Financial Staying Power of Developer.
8. Project Management Team.
9. Realistic Project Development Strategy.
10. Guts and Luck.

While none of these success factors in and of themselves may appear of a critical nature, those of us in the Geothermal development business have witnessed situations where a small detail overlooked or not considered important at the early stages of the development, actually turned out to cripple, if not destroy the success of the Geothermal project. A successful Geothermal development requires the solution to hundreds of problems of which I will try to detail the most important ones that MEI has witnessed to date.

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1. **Market/Power Sales Contract**

The supreme and all-important law of Geothermal development is "if you can't sell it, don't make it." I should also add "at a profit." Too often this particular item is either assumed or overlooked by the developer at the early stages, where the developer assumes he will obtain a PURPA type contract similar to that which had been negotiated by other parties. Very often the PURPA contracts have clauses in them which make the power either difficult, if not impossible to deliver at a profit. MEI elected not to enter into a PURPA contract with the local utility, Utah Power & Light. Instead, MEI concentrated on developing municipal power buyers, and entered into a Power Sales Contract with the City of Provo, Utah. MEI's relationship with its municipal buyer has developed into a sound, joint development arrangement with respect to its steam resource located at Cove Fort. When MEI initiated discussions with local power purchasers, including the local PURPA purchaser, the PURPA rates were an insignificant 20 mil rate. MEI proceeded to actively participate in the Public Service Commission process and eventually has been successful in raising the PURPA rate, along with the other independent power producer organization members, to an estimated 5.4 cents per kWH. This PURPA rate compares to a Power Sales Contract rate in excess of 60 mils with the local municipal government buyer, Provo.

2. **Wheeling Agreement**

Probably everyone at this conference is well familiar with the trials and tribulations of obtaining wheeling agreements, and the number of stalled projects that exist in the West because of failure to obtain a satisfactory wheeling arrangement. MEI's strategy to obtain the first independent, private wheeling agreement in the State of Utah was a very carefully planned strategy coordinated with the City of Provo to utilize our multiple efforts to obtain a wheeling agreement with Utah Power & Light, to transmit MEI's power the approximate 140 miles to the City of Provo distribution system. It should also be noted that the power market in the State of Utah is a rather unique opportunity for marketing and distribution. A number of captive municipal buyers exist within the Utah Power & Light Service District, and until this date there has been no alternative except to wheel over Utah Power & Light's lines. A great deal of progress has been made with Utah Power & Light and the Public Service Commission in allowing qualified Small Power Producers to wheel over Utah Power & Light's lines when there is a legitimate Power Sales Contract in effect with a legitimate power buyer, such as the City of Provo.

3. <u>Transmission Lines</u>

Without close proximity to a transmission distribution system, none of the other elements of a Geothermal resource will make sense during the early stages of development. Transmission lines are expensive to permit and build, and a Small Power Producer developiong a new Geothermal resource will undoubtedly find that the financial investment to build a lengthy transmission line to interconnect with the power grid will be a financial hurdle compounding the development of the resource during its early stages. Fortunately for MEI, its Cove Fort leasehold lies directly on a main interconnection of a 138 and a 46 KV intertie which intersects MEI's property at several locations. Had this line not been available, MEI would have had to look to the construction of an intertie to the next nearest point which was located approximately 23 miles away. The actual investment and the time delays of installing such a line would have seriously hampered such Geothermal development as contemplated by MEI.

4. <u>Resource: Quantity and Quality</u>

Just about everyone I have ever met in the Geothermal business has felt that the discovery of a high quality Geothermal resource seemingly guarantees a successful development. I can tell you without a doubt this is not true. MEI has been fortunate enough to discover a dry steam Geothermal resource. The resource discovery is also probably one of the shallowest dry steam discoveries in the world. With production wells that are less than 1300 feet in depth, costing approximately $400,000 each, and producing 4 - 5 megawatts output each, MEI's development has a great advantage over those resources that either have to pump Geothermal fluids to the surface, or must deal with scaling fluids which compound the generation efficiencies. Several major Geothermal developments in the United States have currently found that the quality of a resource is as important as the quantity of fluid or steam produced. Geothermal corrosion, erosion and scaling has hampered the development of several potentially large Geothermal fields in the western U.S. The quality of the fluid also can have a direct impact on the productivity of the production wells and the longevity of the injection system. Not to be overlooked, the injection system proposed for any specific development can also be a major item that is often overlooked during the early stages of development. Resource permeability, and whether or not inexpensive injection is possible can be a major item that affects the reliability and the economics of the project. Again, MEI has been particularly fortunate in discovering a very clean, very shallow steam system that has displayed excellent production characteristics since its discovery in October of 1983.

5. Regulatory and Environmental Atmosphere

As with the wheeling agreements noted in item 2 above, the regulatory and environmental atmosphere of a proposed development can often be the difference between success and failure. The potential obstacles to development encompassed by this category is virtually limitless. Any one of the regulations or environmental requirements could limit, delay or cripple a potential development from happening. MEI has been particularly fortunate to this point in time by developing a healthy working relationship with all of the Regulatory officials in the State, Federal, and local governments. We have found that if you take the extra time to work with these officials at an early stage of development, you can often eliminate developer's nightmares, and discovering at the eleventh hour that a major item has been missed of a Regulatory nature. MEI is indebted to the tremendous support it has received from the Regulatory officials in the Federal, State and local level within the State of Utah. Particularly important is MEI's relationship that has developed with the Bureau of Land Management and Forest Service in Utah.

6. Reputable Manufacturer

Determining who is or is not a reputable manufacturer can often be a difficult and uncertain process. Just because a major name stands behind the equipment is no guarantee that the equipment will perform as represented. Also, getting a manufacturer to stand behind his representations amd warranties can be a frustrating, if not impossible task under certain situations. MEI's Rule of Thumb is and has been that a contract is only as good as the handshake behind the document. I would strongly suggest that any Small Power Producer that is contemplating entering the development side of the business be certain that his relationships with a potential manufacturer are at a high enough level to not suffer the impact of personnel changes or company policy changes. I can also tell you from my personal experience that there are a number of unethical practices which occur on the part of equipment suppliers. Unfortunately, many of these items are learned the hard way by you and me. I would encourage anyone seeking entry into the small power production business to very carefully and thoroughly investigate all elements of a potential generator manufacturer, equipment supplier, or consultant before making any firm commitments.

7. Financial Staying Power

Another MEI Rule of Thumb in Geothermal development is that everything takes twice as long and costs twice as much to accomplish as originally budgeted. Make sure you have what is called a massive miscellaneous contingency fund (commonly known as an MMCF). My Rule of Thumb is to take whatever you think your contingency budget should be and at least double it.

The second item under this category is not just a reserve of dollars. I strongly urge every potential developer to calculate what the effect of finding themselves delayed from entering production for a period of one or two years will be on the project. What I can tell you from personal experience is that these delays will and do occur regularly. While MEI probably has the best track record in the industry with respect to on-line commercial production from resource discovery in less than twenty-four months, had it not been for errors, miscalculations and contractual difficulties, MEI should have been in production as much as six months sooner. With respect to financing a Geothermal project, MEI has taken an innovative approach wherein it drills the wells and takes all of the resource associated risk with its own funds. Its relationship with its municipal buyers has supplied additional capital for the development of the generation and transformation facilities. While MEI has been offered money from independent investors, the terms and conditions have not been of an acceptable kind to this date. MEI will continue to rely on its own resources and those of its municipal buyers until such time as it can identify an institutional or corporate partner who shares the same development objectives as MEI.

8. <u>Project Team</u>

I cannot say too much about the importance of developing a multi-talented and compatible project team to cover the many items of Geothermal development. MEI has been fortunate to have assembled such a project team during the early days of field discovery. Forsgren-Perkins Engineering of Salt Lake City has acted as lead project engineer responsible for all permitting and design engineering for the Facility. Higginson-Barnett Consultants of Bountiful, Utah have acted as team geologists and hydrologists responsible for the resource identification and well site selection. Also, water right permits and a great deal of public relations efforts have been undertaken by Higginson-Barnett. ThermaSource, Inc. of Santa Rosa, California has performed the functions of drilling engineer, reservoir engineer, and supplied all well testing and drilling management services for the drilling of five MEI wells to date. Professor Ronald DiPippo of Brown & Southeastern Massachusetts University acts as team thermodynamicist and is critical for the review and analysis of proposed generation power cycles for the property. Veizades Engineering of San Francisco, California is responsible for the steam line gathering system. In addition, MEI has two teams of lawyers and an accounting firm that have developed an integral knowledge of the Geothermal laws and requirements.

The second most important item after assembling the team is appropriate team chemistry, and a willingness to work for the benefit of the project and not just for the dollars involved. MEI has been fortunate that every one of its project team members is not only one of the most respected firms in the field, but also has infused the project with energy and enthusiasm which has become contagious to the Regulatory officials and the local communities.

9. Realistic Development Strategy

All too often it appears that developers of Geothermal projects propose development schedules and budgets that are unrealistic given the facts of life with respect to Geothermal development. The Geothermal industry has enough stalled or failed projects on its record list to date. We do not need anymore failures and we certainly do not need disgruntled investors. Any Geothermal failure affects all the rest of us. It is also my impression that the shakeout of "fly by night" consultants and developers has occurred within the industry, leaving serious and legitimate projects, developers, and consultants dominating the field. During the time frame of the late 1970's and the early 1980's when a surplus of government-sponsored contracts existed, a number of underqualified people developed consulting practices or investment schemes which gave the Geothermal industry a tainted image which still exists in part today.

Again, I must urge all members of the Geothermal Community to be realistic about the development obstacles and the risks associated with any Geothermal development. Our community has seen Geothermal successes when conducted by the large corporate entity. However, you can only count the operational Small Power Producer on approximately two fingers as of this writing. We all know of the failures of the entrepreneurial Geothermal developer to this point in time. If we do not self screen and protect our industry from the less reputable developers, consultants, and equipment suppliers, all of our individual lives will become more difficult.

10. Guts and Luck

I think we all must be slightly crazy to be in the Geothermal industry given the economic climate today, the depressed energy prices today, and the elimination of many of the Federal incentives which have made our projects viable in the past. My assessment is that there is much less room for error in the Geothermal community today than there has ever been. An error of even the smallest magnitude could lead to failure. Our community is not for the weak of stomach or weak of pocket book. If you do elect to become a Geothermal developer in the Small Power Producer category, I encourage you to thoroughly do your homework because of the magnitude of the odds against success.

Finally, MEI would not be the success which it is today without tremendous luck. We have been blessed with the financial resources to accomplish our goals, the cooperative and wonderful partnership developed with the City of Provo, the enthusiastic and cooperative support of all of the Federal officials in the Bureau of Land Management and the Forest Service, and the tremendously supportive populous of the State of Utah.

WAP:mh

PROJECT DEVELOPMENT DESERT PEAK

C. P. Diddle and W. C. Gonser

Phillips Petroleum

ABSTRACT

In late 1982 Phillips Petroleum Company began preliminary design of a power plant for Desert Peak in Churchill County, Nevada. Because each geothermal resource is unique, careful consideration of existing process schemes and design technologies was required. This paper will review process studies, examine some of the detail design and discuss the construction program. No attempt will be made to discuss geological aspects of the resource.

INTRODUCTION

Phillips Petroleum Company has obtained approximately 24,000 acres of Federal and Southern Pacific Railroad leases in the Brady-Hazen Known Geothermal Resource Area (KGRA), an area commonly referred to as Desert Peak. This medium temperature hot water dominated resource is located in arid rolling desert of the Hot Springs Mountains, 65 miles northeast of Reno, Nevada. After preliminary evaluations of the resource, Phillips began in late 1982 a comprehensive study of alternatives which ultimately resulted in the current 9 MW facility design.

Process Parameters

Table 1 shows process parameters utilized for Desert Peak.

Table 1

Production Well Characteristics

Average flowrate per well	500,000 lbm/hr.
Average wellhead temp	326°F
Average wellhead pressure	97 PSIA
Average resource temp	400°F
Average resource enthalpy	384 BTU/lb
Steam flash by mass	9.9%

Studies

The process specification for Desert Peak evolved from criteria established by Phillips Geothermal Branch and process studies. Each study was based upon existing conditions at Desert Peak and an objective to generate the most power at the lowest capital cost.

Cooling Towers vs Air Fin Exchangers

Table 2 summarizes electrical power produced by a system cooled by either air fin exchangers or cooling tower.

Table 2

Air Fin/Cooling Tower Electrical Power Production Comparison

Electrical Power	Air Fin	Cooling Tower
Gross Power Output KWH	7279	10022
Parasitic KWH	1509	756
Net Power for Sale KWH	5770	9266
Difference	(3496)	
Effectiveness	62%	

Also, the capital cost of the cooling tower was one third of the cost of the air fin exchangers.

Two Phase Flow vs Wellhead Separation

Wellhead separator systems and two phase flow systems were studied to determine which could provide the lowest pressure drop at the lowest investment and operating costs. Two phase flow was selected because operating and investment costs were reduced by eliminating wellhead separators. By locating the plant downhill of the production wells and insuring there were no pockets in the line; damage due to slug flow was eliminated. Large diameter pipes also assisted in separating fluids.

Floating Power

Floating power means that equipment is sized to take advantage of temperature ranges. As the cooling system responds to lower temperatures more horsepower can be developed by the turbine and more power can be generated. When floating power is considered, the production rate remains constant; however, temperature fluctuations are reflected by annualized mean termperatures. Table 3 summarizes design conditions and power output.

Table 3
Constant Power/Floating Power Comparison

Conditions	Constant Power	Floating Power
Production rate lbm/hr	1,086,000	1,086,000
Cooling Water to Process	67°F(1)	53°F(2)
Cooling Water from Process	107°F(1)	93°F(2)
Electrical Power		
Net Power KWH	10,000	11,050
Percent increase		10.5%

(1) Summer conditions
(2) Mean annual

Binary vs Full Flow Unit

Phillips compared an internally designed binary system with a rotary separator turbine (RST) system. RST power skid operating parameters were provided by Transamerica Delaval Biphase Energy Systems and Phillips developed the process flowsheet for the system. The RST process was selected primarily because it produced more net power at a lower capital cost. Table 4 summarizes both processes.

Table 4
Binary/RST Comparison

	Binary	RST
System Characteristics		
Well flow lbm/hr	1,500,000	1,500,000
Isobutane flow lbm/hr	2,026,000	
Cooling water circulation rate lbm/hr	12,865,000	6,488,620
Electrical Power		
Gross MW	15.08	13.46
Parastic MW	4.10	1.40
Net for sale MW	10.98	12.06
Conversion Efficiency		
Net	7.09%	7.32%
Estimate Cost Differential (1982 costs)	$7,200,000	Base

NOTE: Geothermal fluid was cooled to approximately 167°F in the binary system to accomodate minimum injection temperature.

Current Design

The current design is the result of implementing the conclusions of previously discussed studies. Figure 1 shows the 24 in. and 30 in. two phase gathering system with the plant located at the lowest elevation. As shown by Figure 2 geothermal fluids are separated into high pressure steam and brine in the high pressure separator. High pressure steam flows through a knock out vessel to the steam turbine inlet. Brine from the high pressure separator is divided between the RST and the low pressure separator. Because of low system pressure, the RST cannot process all brine produced in the high pressure separator. Excess brine is flashed in the low pressure separator. Low pressure steam from the RST and low pressure separator enters the steam turbine after any excess moisture is removed by a knock out vessel. Steam at less than atmospheric pressure is discharged from the steam turbine into a direct contact spray condenser where vacuum is provided by steam ejectors. Heat is rejected through a cooling tower and make up for the system is condensate. Brine from the RST flows to the low pressure separator. The injection system includes the discharge from the second stage separator, cooling tower blow down, injection pumps and an injection well. Figure 3 shows the plant layout.

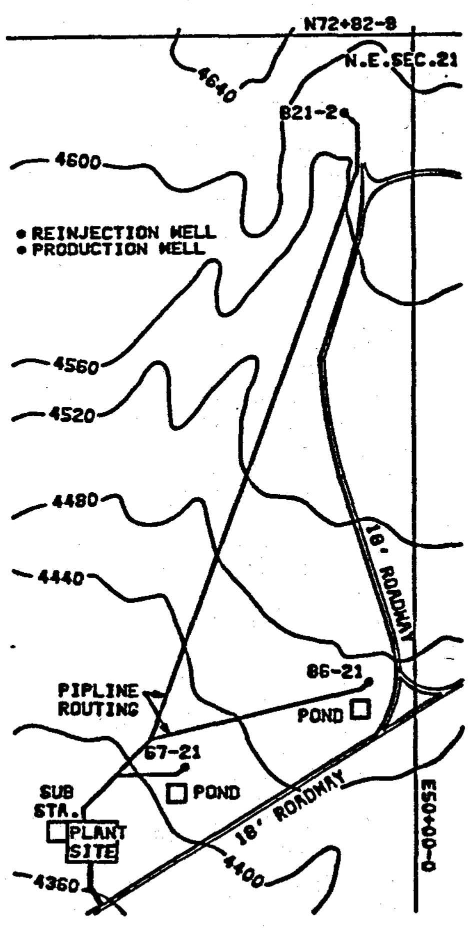
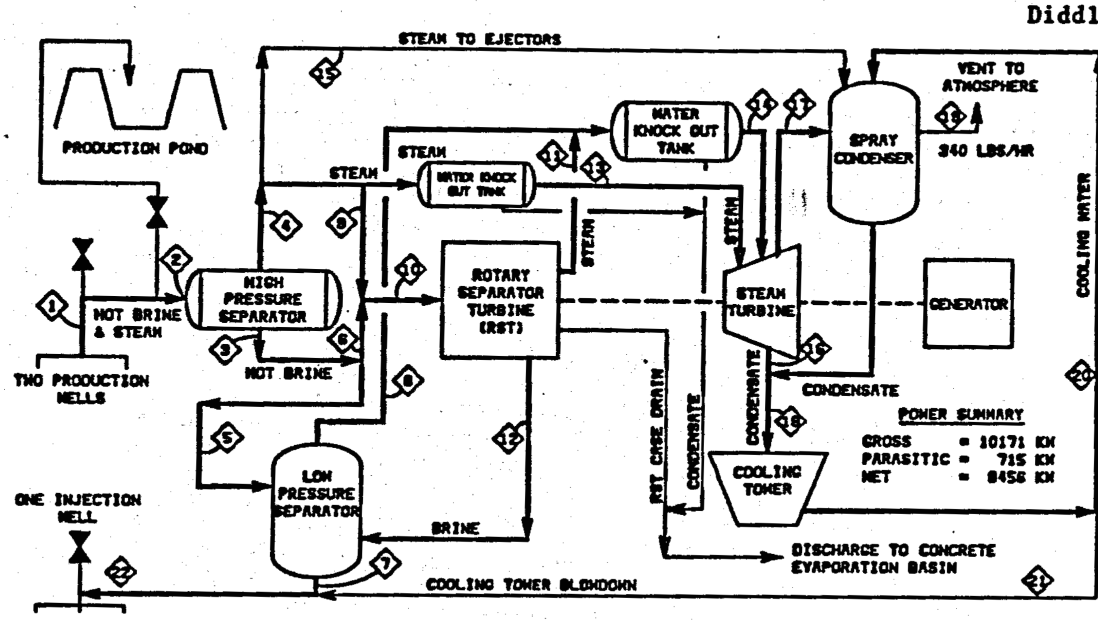


FIGURE 1
DESERT PEAK PLOT PLAN



DESCRIPTION	GEOTHERMAL RESOURCE	FEED	H.P. SEPARATOR LIQUID	H.P. SEPARATOR STEAM	FEED TO L.P. SEPARATOR	LIQUID TO RST	L.P. SEPARATOR LIQUID	L.P. SEPARATOR VAPOR	H.P. RST CONTROL STEAM	TOTAL FEED TO RST	RST OUTLET STEAM	RST OUTLET LIQUID	H.P. STEAM TO TURBINE	L.P. STEAM TO TURBINE	H.P. STEAM TO EJECTORS	LIQUID FROM STEAM TURBINE	VAPOR FROM STEAM TURBINE	LIQUID TO COOLING TOWER	COOLING WATER TO SPRAY COND.	COOLING TOWER BLOWDOWN	RE-INJECTION LIQUID
STREAM NUMBER	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	21	22
LIQUID LBS/HR (X10³)	801	894.4	894.4		84.1	810.3	809.2			807.2		733.3				21.5		3548	3357	24.1	833.3
STEAM LBS/HR (X10³)	88	105.6		105.6				8.2	13.4	18.5	80.4		87.2	88.6	5.0		164.3				
PRESSURE (PSIA)	87	89	89	89	89	89	20	20	89	85	20	41	89	20	89	1.1	1.1				
TEMPERATURE (°F)	326	319.5	319.5	319.5	319.5	319.5	228	228	319.5	318	228	228	319.5	228	319.5	105	105	105	53	53	224

FIGURE 2
9 MW PROCESS FLOW AND MATERIAL BALANCE

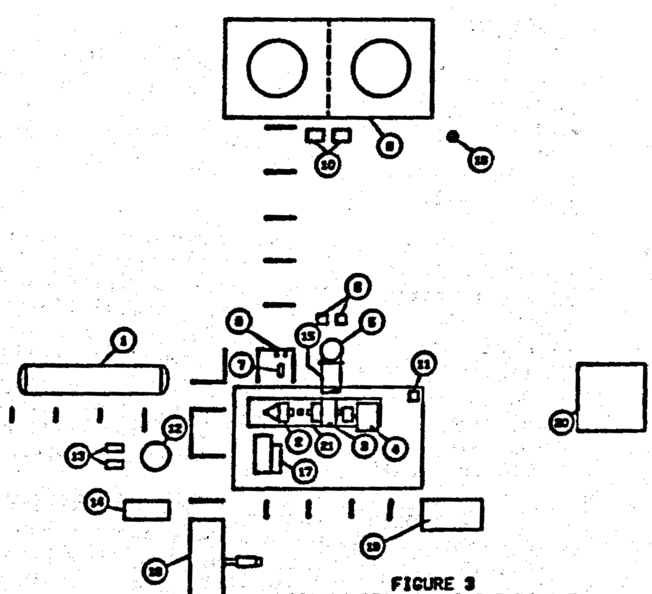


FIGURE 3
DESERT PEAK EQUIPMENT LAYOUT

1. HIGH PRESSURE SEPARATOR
2. ROTARY SEPARATOR TURBINE
3. DUAL STAGE STEAM TURBINE
4. ELECTRICAL GENERATOR
5. DIRECT CONTACT SPRAY COND.
6. CONDENSATE C.W.PUMPS
7. TURBINE DRAIN TANK
8. DRAIN TANK PUMPS
9. COOLING TOWER
10. COOLING TOWER WATER PUMPS
11. NEUTRAL GROUNDING RESISTORS
12. LOW PRESSURE SEPARATOR
13. REINJECTION PUMPS
14. PACKAGED INST. & TOOL AIR SKID
15. TURBINE EXHAUST DUCT
16. VENT STACK
17. LUBE OIL SKID
18. POWER HOUSE & SWITCHGEAR BLDG.
19. CONTROL ROOM & OFFICE
20. RST DRAIN POND
21. PACKAGE POWER GENERATION SKID

Desert Peak Simulator

Process studies, process design and detail design could not have been accomplished in the short time allocated in the project schedule if the Desert Peak Simulator (DPSIMF) had not been developed. The simulator developed by C. P. Diddle, Phillips Petroleum Company models single flash, dual flash and RST systems from production wellhead(s) to the injection wellhead including all auxiliary systems. Its program is written in BASICA for use on the IBM PC. Table 5 shows the variables which can be changed by the engineer with input from the keyboard. The temperature, pressure, flow, and percent vapor at the top of the wellhead are given conditions which can be changed for different reservoirs. The remainder of the variables are selected by the process engineer.

The program provides for change of variables which are listed by letter codes. An input will result in a question to be answered for all codes except: (1) XT = GET OUT OF THE SIMULATOR, (2) RUNS = Causes the program to run after changes of variables are complete and a

Table 5

Engineers Input Screen

```
ENTER VARIABLE CODE LETTERS?
  THIS PROGRAM IS A RST/STEAM TURBINE POWER PLANT SIMULATOR + DPSIMFD ******
****************************************************************************
   Designer of Simulator: Courtney Diddle; Phillips Petroleum Co.          *
     SIMULATOR INPUT VARIABLES -- SYMBOLS (use CAPITAL LETTERS)            *
       TO INITIALIZE = INT then ENTER = Base Case VALUES                   *
   Wellhead Temperature      = WT     HI. Press. Sep. Temp.     =  FA1     *
   Wellhead Flash            = VO     Low Press. Sep. Temp.     =  F1      *
   Wellhead Flow             = FW
   RST INLET Temperature     = FA     RST Feed Rate, LBS/HR     =  RSTF    *
   RST Enhance Stm, LBS.     = VST6   RST Feed Liquid Factor    =  FS      *
   RST Efficiency Factor     = N1     Steam Ejector, LBS/HR     =  SJ      *
   H.P. Steam Vent LBS/HR    = VH     L.P. Steam Vent LBS/HR    =  VL      *
   Stm Turb. Oulet Temp.     = F6     Steam Turb. Efficienty    =  N2&N3   *
   Cooling Twr. H2O Temp.    = F7     Pump Efficiency           =  PEFF    *
   Spray Cond Pump del P     = DP1    Cooling Twr Pump delta P  =  DP2     *
   Blowdown Pump delta P     = DP3    Re-Injection Pump delta P =  DP4     *
   RETURN TO STARTING MENU   = MU     GET OUT OF THE PROGRAM    =  XT      *
   RUN NUMBER                = RUNA   RUN SIMULATOR             =  RUNS    *
   ENTER - Your NAME         = N$     ENTER - Plant Site NAME   =  S$      *
****************************************************************************
ENTER VARIABLE CODE LETTERS?
```

run is desired. (3) RUNA = Allows for an over-ride of the Run Number, since the program will automatically increment the run number by one (1) each RUNS.

The simulator contains a steam table with saturated data between 32-705 degrees F. The program will interpolate as a function of temperature. Output is in the form of a single page summary (Table 6) which includes gross, net and parasitic power or a six page detailed printout. Details include process parameters of all major components, pump horsepower, and power developed by RST and steam turbine.

Table 6

Single Page Power Summary Sequence

```
****************************************************
ENTER VARIABLE CODE LETTERS ? RUNS
  The DPSIMF SIMULATOR is now calculating the
  problem.
****************************************************
THIS PROGRAM IS A RST-STEAM TURB POWER PLANT
SIMULATOR = DPSIMFD
Designer of Simulator: Courtney Diddle
                       Phillips Petroleum Co.
DATE OF RUN = 02-22-1985
TIME OF RUN = 08:28:00      RUN NO. = 1
ENG'R:  J. Q. ENGINEER
  SUMMARY OF POWER OUTPUT IN KILOWATT HOURS
  SITE = ANYWHERE, WORLD
  RST POWER AT N1 EFF.               =    657.7
  HI.PR. TURB AT N2 EFF.             =   5457.0
  L.P. TURN AT N3 EFF.               =   4046.4
  GROSS POWER-TOTAL POWER            =  10161.2
  TOTAL PARASITIC POWER              -    714.8
  NET POWER FOR SALE                 =   9446.3
Number of Variable CHANGES           =      0.0
  (Maximum = 5 different)
****************************************************
IS A HARDCOPY REQUIRED? Y OR N?
```

Deserk Peak Graphic Simulator

Phillips is currently developing an interactive graphic simulator of the Desert Peak process. It will also be able to simulate single flash and dual flash systems. The advantage of the graphic simulator is that variables can be increased or decreased by holding one's finger on the appropriate key. As the variable changes the engineer can observe corresponding changes in power production and other system parameters.

Detail Design

Several changes to project premises were made to accomodate solutions to problems which were solved during detail design. The impact on other equipment specifications were determined by DPSIMF which provided for maximizing net power at all times.

Liquid at saturation temperature and pressure leaving the first stage separator is flashed due to normal pressure drop in piping enroute to the RST. This could cause unequal distribution of liquid to RST nozzles. After study, a cooler condensate injection system was designed to be used if required. The DPSIMF calculated quantities of liquid flashed and quantities of condensate required to lower the temperature to match the expected pressure at the RST inlet.

The vent-relief system is essential for the management of steam during the start-up of the RST and dual stage steam turbine. Low pressure steam will be vented while the turbine is started utilizing high pressure steam. Optimization of the size of the vent control valves was accomplished by calculating the expected flow rates as a function of changing back pressure. The calculation was made by the DPSIMF simulator.

In order to meet excepted operating conditions the brine disposal ponds which were premised to be installed if required have been constructed. Diverting production to the ponds will assist in limiting the rate of the increase in the systems temperature during start-up. Also solids loosenedby well cleaning can be prevented from entering production pipelines and equipment.

As the operating and startup procedures developed, it was determined that a distributed control and permissive interlock systems would be required. A programable controller with 8K memory and 128 I/O points was selected to implement shut-down logic and permissive start sequencing. The process will be controlled by 4 eight loop programable controllers. A CRT station will be used to monitor and make process adjustment. Because the system floats on the wet bulb temperature and production characteristics change as the result of well scaling all systems must be kept in balance and have a reasonable operation range. It would be impossible to manually control this dynamic system.

Construction

The overall project schedule was developed to take advantage of all tax incentives and be operational by December 31, 1985. In order to meet this objective the construction philosophy provide for separate site preparation, plant erection, insulation and painting contracts. Site preparation was completed in mid March 1985 and the main contract was awarded in early April. The RST power skid is scheduled to be shipped by mid-July and plant start-up is scheduled for December.

References

Phillips Petroleum Company Computer Programs
a) DPSIMF RST-Steam Turbine Power Plant Simulator
b) DPGSIM RST-Steam Turbine Power Plant Graphic Simulator

Cerini, D. J., Diddle, C. P. and Gonser, W. C. Project Development Desert Peak 9MW Power Plant Proceedings Eight Annual Geothermal Resources Council pgs. 33-39, 1984.

DESIGN, CONSTRUCTION AND OPERATION OF THE MAMMOTH GEOTHERMAL POWER PLANTS

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ABSTRACT

The world's first modular air-cooled binary plant went on line in November of 1984 near Mammoth Lakes, California. It is now operating reliably and producing power at rates in excess of design. Availability exceeds 90%. The facility consists of four production wells, three injection wells and two identical binary power plants each having a year-round net capacity of 3,500 kW, exclusive of well pumping power.

The reservoir is a low-salinity (1,500 ppm) moderate temperature (340°F) resource. Multi-stage shaft driven pumps are employed to deliver the hot water to the plant under sufficient pressure to eliminate flashing and prevent scaling.

Air cooling is used to reject heat to the atmosphere. The result is that there are no air or water emissions from either the geothermal resource or from the plants.

BACKGROUND

The Mammoth Geothermal Project is located within the Long Valley Known Geothermal Resources Area (KGRA) on the eastern slope of the Sierra Nevada mountain range of California some 300 miles north of Los Angeles. Three miles west of the plant is the village of Mammoth Lakes, and well-known winter and summer resort.

The plant is owned by Mammoth-Pacific (M-P), a joint venture of Pcifica Geothermal Company (a subsidiary of Pacific Lighting Corporation of Los Angeles) and Mammoth Binary Power Company. The general partner of Mammoth Binary Power Company is Holt Geothermal Company, an affiliate of The Ben Holt Company based in Pasadena, California.

Design and construction was handled by The Ben Holt Co., who also through the Mammoth Binary Power Co. operates the plant.

Nearly all of the residential and commercial space heating in the Mammoth Lakes area is electrical, served by the Southern California Edison Company (Edison). Electrical usage peaks in the wintertime, unlike the rest of the Edison system. While some power is provided by hydro plants in the area, most of the Edison supply arrives via a transmission line connecting to Edison facilities in the Mojave desert some 200 miles to the south. Peak power consumption in the area is about 40 MWe.

Field construction of the power plants was minimized by the use of modular design. Two identical units were built, side by side, with common utilities and common spare equipment. Wherever possible, equipment was skid-mounted and/or shop fabricated to minimize field costs. All of the system components are commercially available.

Design and operation of the plant takes advantage of the low ambient temperatures at the plant site. The plant is at an elevation of 7300 feet with an annual average dry bulb temperature of approximately 40°F. Condensation of the working fluid uses floating cooling. That is, the condensing temperature is allowed to vary with changes in the inlet air temperature. Power production during the summer is lower than average, but the high power production during the rest of the year makes up for the low summer production.

The geothermal brine at Casa Diablo has a dissolved solids content of about 1500 ppm and is non-corrosive. As a result, the piping and power plant have been built with carbon steel as the primary material of construction.

Reservoir

Eight geothermal wells were drilled on Magma's property and flow tested in the early sixties. This early work demonstrated the existence of a reservoir of hot water at shallow depths (400 to 800 ft.). Reservoir temperatures averaged about 330°F and total dissolved solids were about 1500 ppm. The early test work involved free flowing the wells for periods varying from a few days to a few weeks. Carbon dioxide was evolved during these tests, resulting in calcite formation in the well bore.

A shaft-driven downhole pump was used in subsequent test work to eliminate calcite formation by maintaining single phase flow in the wells and surface equipment.

The geology of the area has been described in a paper, "The Hydrothermal System of Long Valley Caldera, California" (USGS Professional Paper 1044-A).

Design Criteria

The following criteria were the key elements in deciding upon the design.

The facility must be environmentally acceptable since it is surrounded with National Forest land in an area possessing great scenic and recreational value.

In order to minimize construction costs in a remote area, the facility should employ modular construction techniques to the maximum extent possible.

In order to qualify as a base load facility, it should be designed for high availability and reliability.

These considerations led to the choice of a simple binary cycle plant employing 100% air cooling. The geothermal fluid is maintained in a liquid state throughout and 100% of the fluid is reinjected. Moreover, no cooling water is required in an area where fresh water is at a premium. Thus the plant is a pollution-free installation.

Air cooling also permits taking advantage of the cold air as a cooling medium particularly in the wintertime, thereby increasing thermal efficiency and power output by reducing condensing pressures in the season when power is most needed.

Low construction costs and high reliability are ensured by providing twin units, each having a capacity of 3.5 MWe, calculated on a yearly basis.

System Description

Isobutane is the working fluid in a Rankine cycle. Vaporization is subcritical though near the critical point. Condensation of the turbine exhaust is in the air coolers.

The design basis of each module is as follows:

1. The Brine
   a. Temperature in - 330°F
   b. Temperature out - 150°F to 180°F depending on ambient air temperature
   c. Flow rate - 640,000 lbs/hr
2. The Working Fluid
   a. Composition - Isobutane
   b. Turbine inlet - 500 psia, 280°F
   c. Condensing temperature - 70°F to 120°F depending on ambient air temperature
   d. Cooling - 100% air
   e. Flow rate - 580,000 lbs/hr

Operation using the floating mode concept results in varying power outputs throughout the year. Monthly average production is near 8 MWe during the winter with low air temperatures and low turbine back pressures. Power during the summer is about 6 MWe due to higher turbine back pressures and off-design operation. The total annual power output is higher using this floating mode concept than if a single high air temperature was chosen as the design point for year-round operation.

The nameplate generator capacity for each unit is 5,000 kW. Parasitic load for each unit is 1,000 kW. Thus the design net power for sale is 4,000 kW. However, year-round output is estimated to be 3,500 kW.

Field pumping requires about 300 kW for each unit.

The geothermal brine is pumped from the production wells and through the heat exchangers using vertical line-shaft turbine pumps. Cooled brine leaving the heat exchangers is pressurized for reinjection by centrifugal pumps at the plant site.

CONSTRUCTION HISTORY

Groundbreaking for the facility started in September of 1983 and the power plant was mechanically complete and ready for operation in October of 1984. Prior to the onset of severe winter weather, foundations were poured, structural steel supports for the air coolers were installed, and the office, control room and warehouse building were built. Construction resumed in April of 1984.

Four production wells and two injection wells were drilled in the fall and winter months. Testing was limited to short term open flow tests into Baker tanks.

The production pumps were installed in the spring and most of the field piping completed. A program of production and injection well testing was undertaken in the summer and early fall.

OPERATING HISTORY

The operatinghistory of the plant and field as of June 1, 1985 may be summarized as follows:

Wells

The four original production wells (MBP-1,2,4 & 5) were drilled to a depth of 650'. Casing was set and cemented at 250' and a slotted liner (9-5/8")set at depth. Pumps were set at 600'.

One injection well (IW-2) was drilled to a depth of 1,800 feet. The injection interval was 1,300 to 1,900 feet. The second injection well was a converted well drilled in 1979 by Union Oil Company. It was plugged at 1,900 feet. The 7" liner was slotted from 1,100 to 1,900 feet.

During early operation, three of the wells (MBP-2,4 & 5) developed communication to the surface indicating a failure of the casing cement. The surface eruptions adjacent to the wells were sufficiently serious to require reworking MBP-4 and MBP-5 and abandonment of MBP-2. The reworks were successful and involved removing the casing and liner, resetting and cementing the casing to 400 feet.

Late in 1984 a new well, MBP-3, was drilled as well as a third injection well (IW-1).

At the present time, three of the wells (MBP-1,3 & 4) are sufficient to supply the plant (about 2,800 gpm at 340°F) and appear to be pump limited. Very little drawdown occurs on each well and wellhead temperatures have remained constant.

The production pumps have given excellent service and show no indication of reduced performance as a result of corrosion or erosion.

Two of the three injection wells are in service at any given time. Injection pressures at the wellhead are low and the injection pumps are not required.

Plant

The first unit (Unit 100) was turned over to operations in October. In November chemical cleaning of the isobutane circuit was completed and isobutane loaded. Circulation was established and the first power was sent to the grid in late November, 1984. Firm operation was established in February, 1985. Unit 200 first delivered power to the grid in March of 1985.

Numerous startup problems have been encountered and solved, not the least of which was the necessity of starting up during the winter. The current status of the power plant equipment is as follows:

Isobutane Pumps

These are vertical multi-stage centrifugals that have operated according to specifications.

Brine-Isobutane Heat Exchangers

Each unit is equipped with six fixed tube sheet single-pass heat exchangers. No scaling or corrosion on either shell or tube-side has been observed. Excess surface was provided to allow for scale buildup. So far, no measurable decreases in overall transfer rates have been observed.

During the winter we froze and broke a few tubes during startup. They were plugged off. Nor further leakage has been observed.

Air Coolers

Each unit contains eleven air cooler sections in parallel. Each section is equipped with three fans. The air coolers have performed in accordance with expectations. Maldistribution of isobutane to the coolers does not appear to be a problem.

Turbine-Generators

The turbine in each unit is a radial-inflow type rotating at 11,000 rpm and driving a 5,000 kW synchronous generator through a gear reduction unit. These three units are mounted on a single skid. A second skid contains the lube oil storage, degassing and pumping equipment.

Normal startup problems have been encountered, principally relating to the control system components. A major problem has been the unexpected resonance failure of several turbine wheels. This problem appears to have been satisfactorily remedied by the vendor.

STAFFING

We employ two operators per shift around the clock. Three permanent maintenance technicians are employed on days. A plant manager, a plant superintendent and a secretary complete the staff. Accounts payable, payroll and technical services are provided by The Ben Holt Co.'s Pasadena office.

ECONOMICS

The power plants were constructed within the original budget estimate of $10M. This is equivalent at the design output of 8,000 kW to a cost of $1,250/kW.

The field budget of $2.5M was exceeded by the need for remedial work and drilling additional wells.

FUTURE PLANS

M-P has entered into a power sales agreement with Edison for an additional 20,000 kW (gross). Preliminary work is underway.

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DELIVERABILITY AND ITS EFFECT ON GEOTHERMAL POWER COSTS

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Abstract

The deliverability of liquid-dominated geothermal reservoirs is presented in terms of reservoir performance, inflow performance, and wellbore performance. Water influx modeling is used to match the performance of Wairakei in New Zealand, and Ahuachapan in El Salvador. The inflow performance is given in terms of a linear productivity index for liquid-only flow, and a solution-gas drive relationship for two-phase flow. A 9-5/8" production well is assumed, flowing 250°C water from 900 m depth, with a wellhead pressure of 100 psia. A Geothermal Development Model, that couples reservoir deliverability and power plant performance, and assigns costs to both, is used to illustrate how the development cost of geothermal electric power projects can be estimated.

Introduction

The performance of reservoir/wellbore systems is perhaps the major cause of uncertainty in geothermal field development decisions, at least in comparison to the performance of surface facilities and power plants. Because of this uncertainty it is difficult to optimize the development of liquid-dominated resources for electric power production. This may be the reason why issues of geothermal resource exploitation and power plant operations tend to be dealt with separately in the literature. In this paper, we couple the reservoir and economical issues in a Geothermal Development Model, and consider the effect of deliverability on the cost of geothermal electric power from liquid-dominated resources. The overall performance of a reservoir/wellbore system with time is what we call deliverability. It has three components: reservoir performance, inflow performance, and wellbore performance.

Reservoir Performance

A reservoir model describes the change in reservoir pressure as a function of fluid production. The reservoir models available range from simple decline curves, through lumped-parameter models, to distributed-parameter models. Grant (1983) has reviewed these for geothermal uses. Figure 1 shows the drawdown in reservoir pressure versus cumulative mass withdrawal for three liquid-dominated reservoirs: Ahuachapan, Svartsengi, and Wairakei. These data were taken from Vides (1982) and Quintanilla (1983) for Ahuachapan, and from Gudmundsson et al. (1985) and Stacey and Thain (1983) for Svartsengi and Wairakei, respectively. Figure 1 shows that the drawdown in the three reservoirs is similar. The Wairakei reservoir is known to be larger than the others. In terms of surface area, it is reported to be about 15 km^2 (Donaldson and Grant, 1978), while Ahuachapan and Svartsengi are likely to be in the range 5-10 km^2. Figure 1 suggests that Svartsengi is the smallest of the three; it shows greater drawdown at lower levels of production. Through 1982, the average rate of fluid production from Wairakei was about 1500 kg/s; the rate at Ahuachapan was about 600 kg/s through 1983; from Svartsengi the average rate was about 150 kg/s, currently it is about 300 kg/s. The three fields are reaching nearly the same level of drawdown as cumulative mass production increases. The long-term drawdown appears to be about 3 MPa, although the drawdown in the two smaller fields has not levelled off as much as Wairakei. We observe that these geothermal liquid-dominated reservoirs exhibit a similar drawdown characteristic; their overall uniform behavior suggests they can be modeled using similar reservoir engineering techniques. The Wairakei, Ahuachapan, and Svartsengi reservoirs have a steam/vapor-dominated zone above the main liquid-dominated zone; see Donaldson and Grant (1981), Rivera-R. et al. (1983), and Gudmundsson and Thorhallsson (1986) for details, respectively.

We elected to use a lumped-parameter model with water influx to study the performance

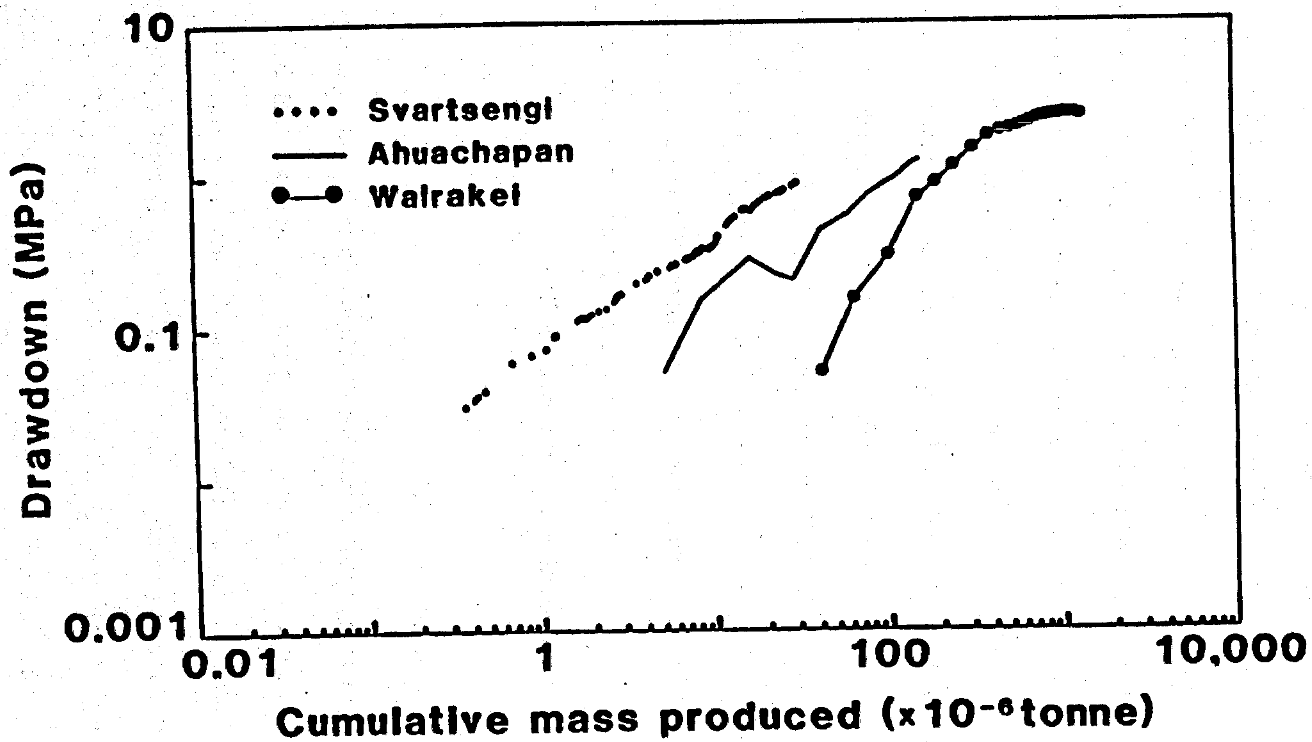

Figure 1. Drawdown in reservoir pressure in three liquid-dominate reservoirs.

Wellbore Performance

We considered wells that produce steam/water mixtures at the wellhead. In the main they will have liquid water feedzones; in some cases the fluid will be two-phase, as in Figure 3 when the well flowing pressure falls below the saturation pressure. Wellbore performance concerns the pressure drop from the bottom or main feedzone to the wellhead. This performance depends on many variables, including: fluid enthalpy, reservoir pressure, well diameter and depth, and wellhead pressure. Ambastha and Gudmundsson (1986) present flowing pressure and temperature profiles in 10 two-phase geothermal wells; they also match the data using a wellbore simulator based on the Orkiszewski (1967) pressure drop correlations. Such a simulator can be used to construct performance curves for two-phase geothermal wells. Butz and Plooster (1979) and Butz (1980) have published performance curves for well Utah State 14-2. The curves are based on a fluid enthalpy of 1100 kJ/kg (liquid water at 250°C), a reservoir pressure of about 9.7 MPa (1430 psia) at a depth of 900 m, and a wellhead pressure of 0.69 MPa (100 psia). We present these curves in Figure 4 as wellbore performance curves for a 9-5/8" and 13-3/8" casing from 900 m depth to surface. The wellbore performance curves are independent of inflow performance and reservoir performance; when we couple them, however, we obtain the reservoir/wellbore system deliverability.

Geothermal Development Model

Decision making about geothermal developments deals with objectives, choices, and constraints. To optimize this decision making process, we need a model that includes both the physical and economic features of development. We have made such a model from the point of view of reservoir engineering, to study the effect of deliverability on electric power costs. The elements of the Geothermal Development Model are shown in Figure 5. Several physical models or features can be selected for each of these elements; similarly, different problems can be investigated: (1) reservoir can be modeled using decline curves, lumped-parameter models, or distributed-parameter models, (2) wellbore flow can be modeled using generalized, or flow of the three liquid-dominated reservoirs; specifically, the simplified method of Hurst (1958). This method was used by Olsen (1984) and Gudmundsson and Olsen (1985) to match the production history of the Svartsengi reservoir. Marcou (1985) extended this work to include Ahuchapan and Wairakei - the latter match will be discussed here. We assumed the reservoir to be radial and finite, and the supporting aquifer to be radial and infinite. In water influx modeling we focus on fluid flow across the boundary between the hot reservoir and surrounding warm aquifers. The reservoir is taken to have homogeneous properties and uniform pressure. The model equation is given in terms of the warm aquifer physical properties; the permeability-thickness product of the reservoir and aquifer are taken to be equal; the compressibility of the reservoir and aquifer provide the main contrast in properties. In a general way, the pressure response of the reservoir is dominated by the flow of water into the main reservoir volume from surrounding aquifers. If there was no fluid flowing into the reservoir, it could be modeled as a constant volume tank under decompression or drainage. There are three constants used in the Hurst (1958) simplified method

$$A = \frac{\mu_a}{2\,\pi\,kh\,\rho_a}$$

$$B = \frac{k}{\phi\,\mu_a\,c_a\,r_r^2}$$

$$C = \frac{2\,c_a}{c_r}$$

where the symbols have the usual meaning, and the subscripts a and r stand for aquifer and reservoir, respectively. Grant et al. (1982) showed that for typical geothermal reservoir conditions, the compressibility of liquid water is of the order of 10^{-9} Pa^{-1}, steam vapor 10^{-7} Pa^{-1}, and a two-phase mixture 10^{-6} Pa^{-1}. This range of several orders of magnitudes affects greatly the pressure response of geothermal reservoirs, particularly when two-phase zones are present.

We matched the Wairakei data using 3 years, 6 years, 12 years, and 25 years of production history. The match parameters obtained from the partial data sets were then used to predict the drawdown in reservoir pressure for the 25 years of history. Our matches are shown in Figure 2. We wanted to test the forecasting ability of the model. Using the first three years of history, the model overpredicts the drawdown; using six years or more the match between model and actual drawdown was reasonable. That is, using six years of production history, we were able to forecast the next twenty years of drawdown with reasonable success. The following values of model constants were obtained from the full match: $A = 6.7 \times 10^2$ Pa.s/kg; $B = 9.3 \times 10^{-8}\ s^{-1}$; $C = 0.19$. For an aquifer compressibility of $2.4 \times 10^{-9}\ Pa^{-1}$, the reservoir compressibility becomes $2.6 \times 10^{-8}\ Pa^{-1}$. It appears from this result that boiling in the two-phase zone does not significantly influence the compressibility of the Wairakei reservoir.

Inflow Performance

The relationship between reservoir pressure and wellbore flowing pressure we call inflow performance. In general, the mass flowrate w increases with increasing difference between the two pressures, as expressed by the relationship

$$w = J\,(p_r - p_{wf})$$

where J is a constant called the productivity index. This equation usually applies for single-phase laminar flow into the wellbore; single-phase Darcy-type flow. In the case of geothermal wells, the well flowing pressure p_{wf} ought to be measured at the depth of the well's main feed-zone fracture. The linear productivity index has been used by Gudmundsson (1984) in the calculation of output curves of geothermal wells with single-phase feedzones, using a wellbore simulator. We use it here for single-phase flow from the reservoir into the wellbore; when the well flowing pressure p_{wf} is greater than the saturation pressure p_{sat} of water. Figure 3 shows that inflow performance of well Utah State 14-2 in the Roosevelt Hot Springs geothermal area. The data were taken from Butz and Plooster (1979), and Butz (1980); see also Menzies (1982). The productivity index of this well was determined to be about 40 tonne/hr.MPa (600 lb/hr.psi), which is an average-kind of a well. A more productive well is well 12 in the Svartsengi field, which was reported by Gudmundsson (1984b) to have a productivity index of about

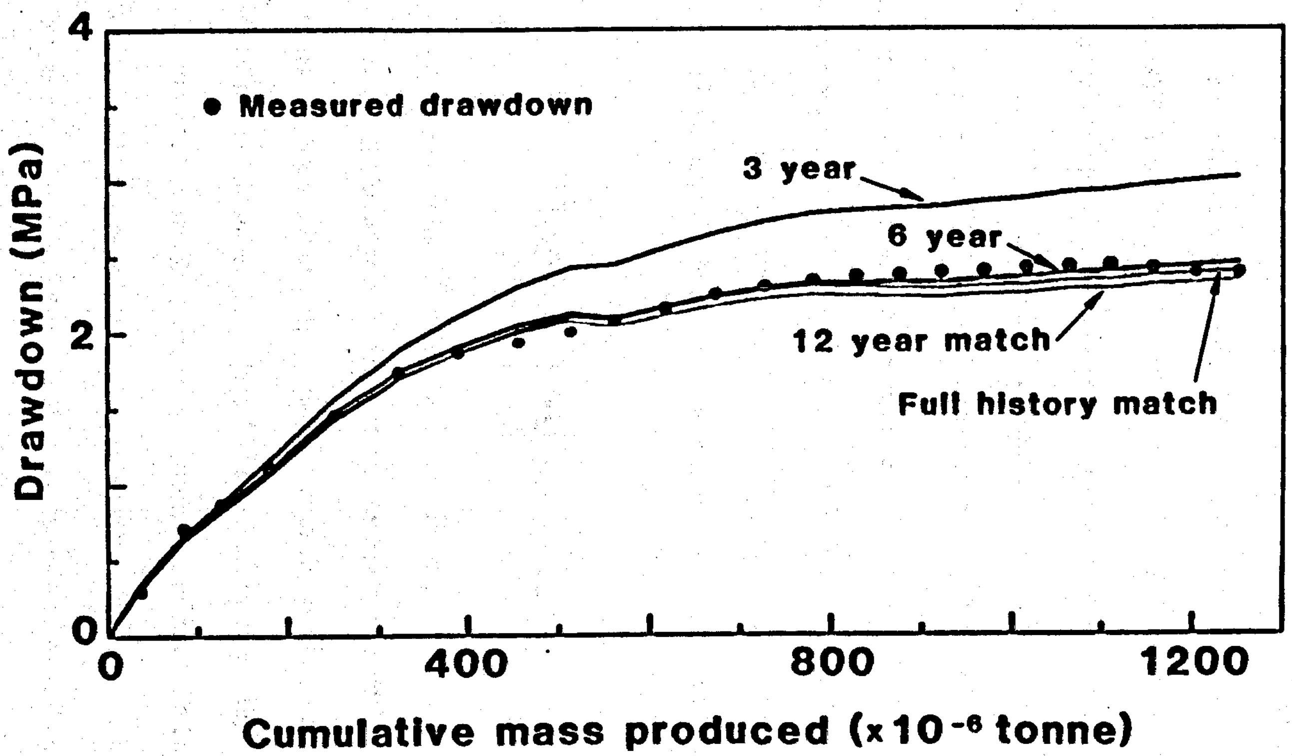

Figure 2. History match and forecast of drawdown for Wairakei.

100 tonne/hr.MPa (1500 lb/hr.psi). We note that the productivity index is the inverse slope of the line above p_{sat} in Figure 3. A larger productivity index, therefore, means that a greater flowrate is achieved for the same pressure drive. Furthermore, the advantage of increased casing size is greater for wells with a large productivity index.

At relatively high flowrates, and when a steam/water mixture flows from the reservoir into the wellbore, the relationship between mass flowrate w and driving pressure $(p_r - p_{wf})$, is likely to become non-linear. This problem was investigated by Vogel (1968) for solution-gas drive reservoirs in the petroleum industry; Menzies (1982) considered a similar problem of steam/water flow in fractures, including the effect of heat transfer from the rock to two-phase mixture. The Vogel-method was used in our work because of its simplicity.

The Vogel (1968) inflow performance curve is an empirical relationship, obtained for the situation where gas is coming out of solution; the flow of oil from its bubble point to increasing gas/oil ratio. We decided to apply the Vogel (1968) relationship to only the two-phase flow part of the geothermal inflow performance curve. For this situation the relationship takes the form

$$\frac{\Delta w}{\Delta w_{max}} = 1.0 - 0.2\left[\frac{p_{wf}}{p_{sat}}\right] - 0.8\left[\frac{p_{wf}}{p_{sat}}\right]^2$$

The Δw is the incremental mass flowrate we achieve by lowering the well flowing pressure below the fluid's saturation pressure. The Δw_{max} is what would ideally be achieved if the well flowing pressure became negligible; in other words, if there was negligible pressure drop in the wellbore. The square term in the modified Vogel (1968) relationship takes into account turbulent losses and other non-linear effects. The inflow performance below the saturation pressure in Figure 3 is a solution-gas-type relationship. We see that the inflow performance of well Utah State 14-2 can be matched with a linear productivity index at pressures above the saturation pressure, and a combined linear and non-linear relationship at lower pressures.

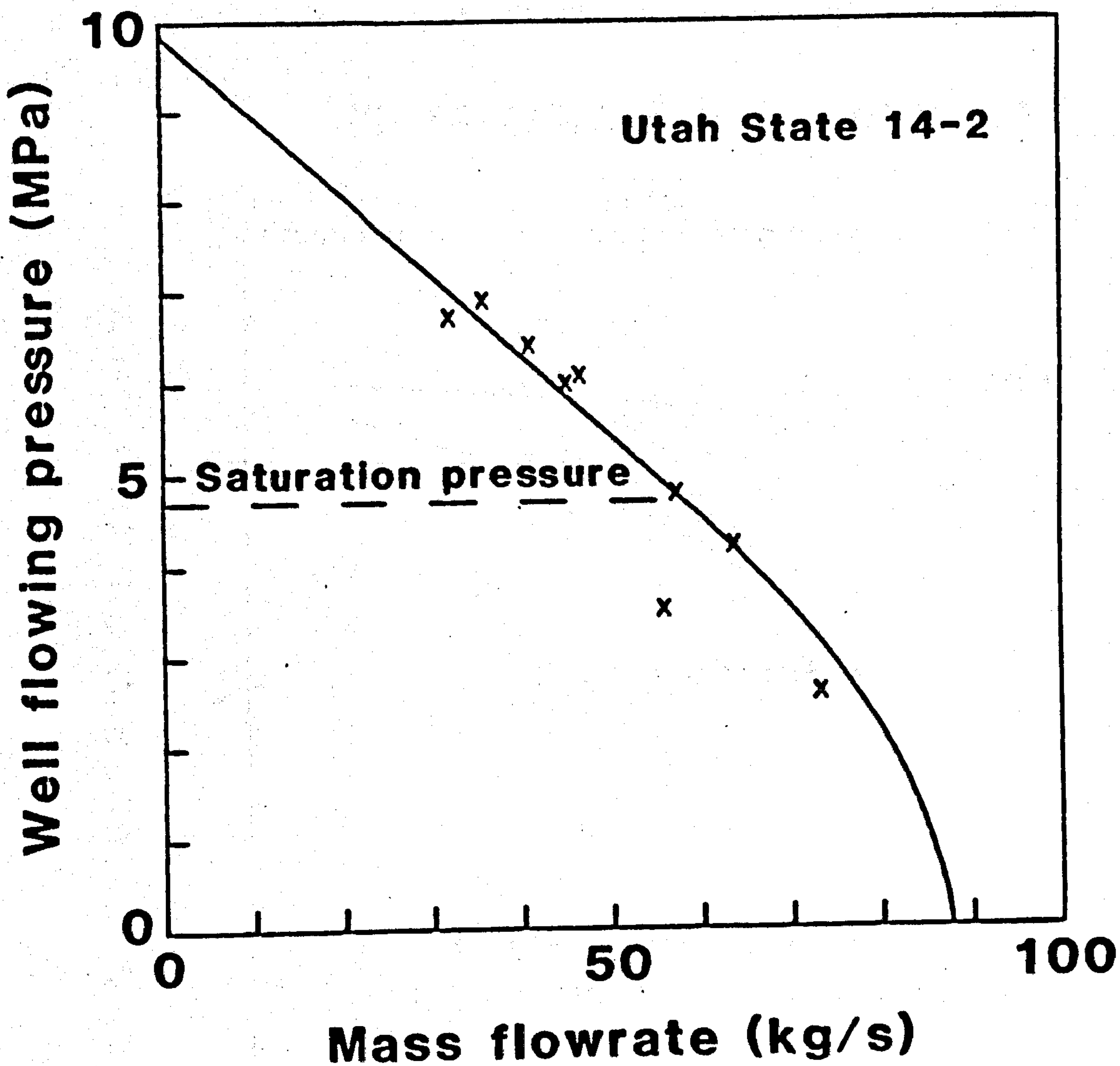

Figure 3. Inflow performance of well Utah State 14-2.

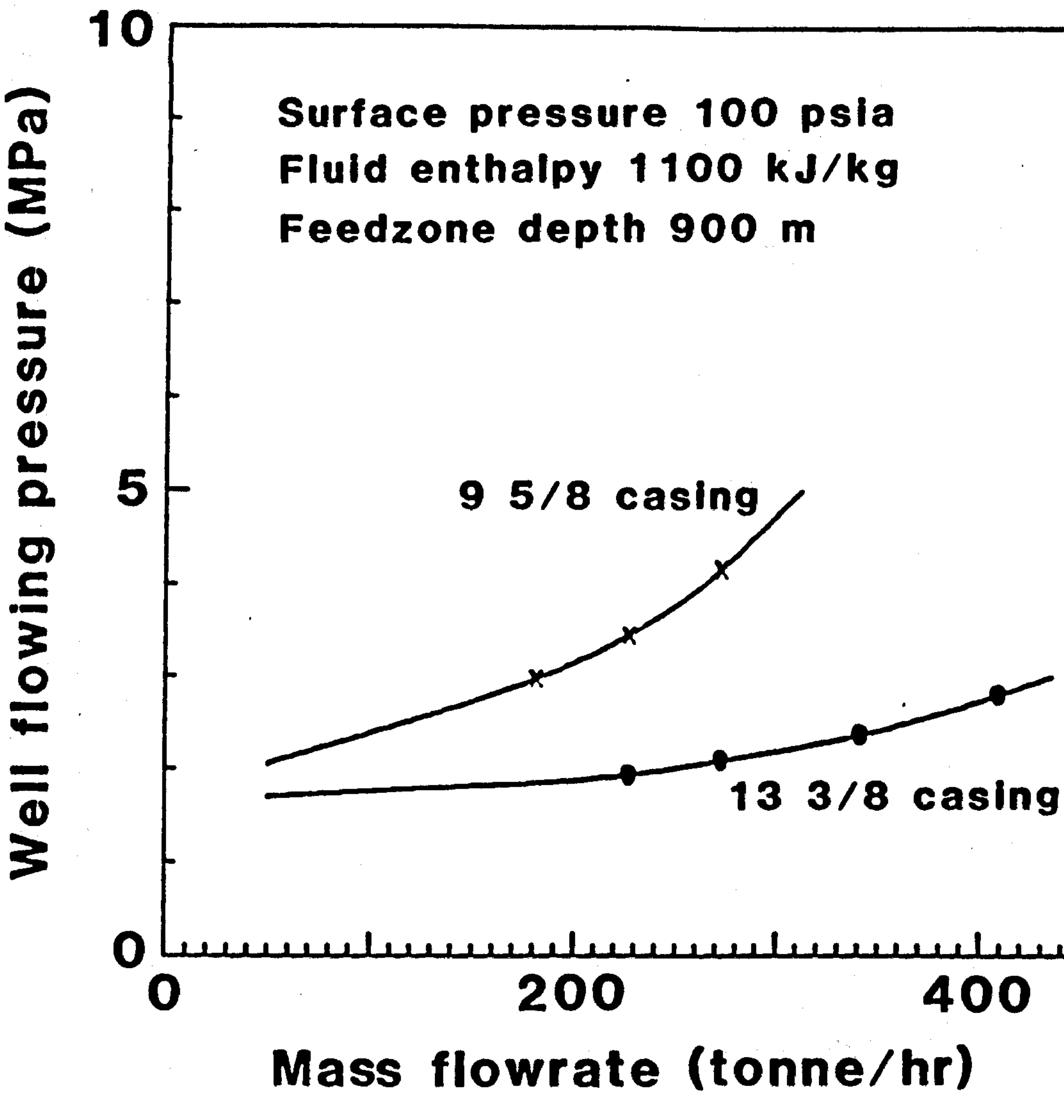

Figure 4. Wellbore performance of 9-5/8" and 13-3/8" wells.

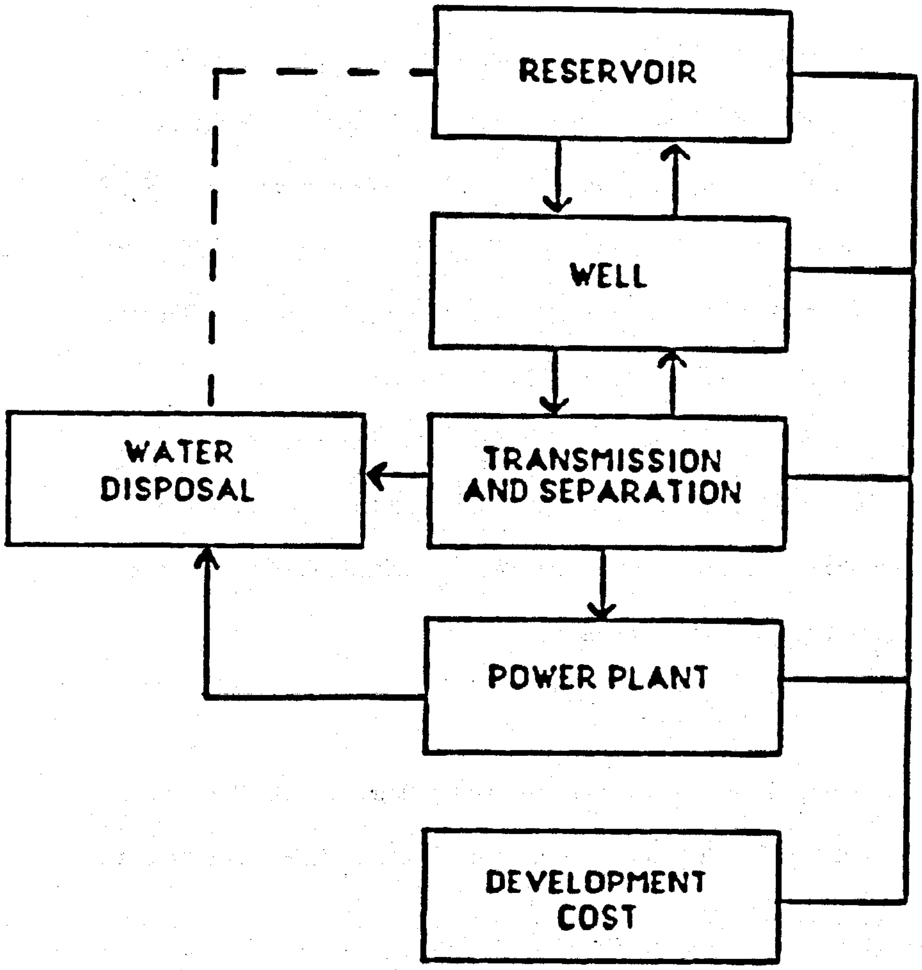

Figure 5. Elements of geothermal development model.

pattern specific two-phase flow models, (3) surface facilities can have separators at each wellhead, or a central separator station (4) wellhead units and a central station are typical power plant choices (5) spent fluids can be disposed of at the surface or injected back into the reservoir, with or without chemical treatment. And, for whatever choices we make, there are associated costs, and constraints.

Above we presented the main features of the reservoir, inflow, and wellbore performances used. The following are a few details needed to complete the coupling of the individual performances to get the reservoir/wellbore system deliverability. We decided to use a 9-5/8" wellbore casing. The inflow performance curve in Figure 3, the 9-5/8" wellbore casing performance curve in Figure 4, intersect at a total flowrate of 220 tonne/hr (60 kg/s). This flowrate then, is the initial flowrate from a well like Utah State 14-2, for a wellhead pressure of 0.69 MPa (100 psia). With decreasing reservoir pressure, this flowrate will also decrease, because the inflow performance curve will move down in parallel with the initial curve, because it is constrained to go through the current reservoir pressure. We determined the deliverability of our typical well to follow the approximate relationship

$$w = 30\, p_r - 60$$

where w is mixture flowrate (kg/s) and p_r the average reservoir pressure (MPa). We used this equation in the development model to determine how many wells are needed at start-up, and when new wells are needed.

For a mixture enthalpy of 1100 kJ/kg and a separator pressure of 0.69 MPa, the mass fraction of steam is 22 percent. We reviewed a number of publications on geothermal electric power plants to obtain a value for the conversion efficiency of steam to electric power (see Marcou, 1985). We found that the following values were representative: condenser plants 8 tonne/hr.MW and back-pressure plants 15 tonne/hr.MW. We assumed negligible pressure loss from the wellhead to power plant. It follows that a well like Utah State 14-2 can generate about 6 MW of electric power initially. The average capacity of wells in liquid-dominated reservoirs worldwide is about 5 MW.

We divided the total cost of development into steamfield costs and power plant costs. Again, we reviewed a number of publications on geothermal electric power developments. The studies reviewed indicated that steamfield costs range from 25 to 50 percent of total development cost. Two of the references are reports by Holt and Ghormley (1976) and Southan et al. (1983). We decided to select typical cost values for use in the development model. The initial investment cost of central power plants was taken as 1.3 M$ per installed MW. This is cost in 1984 dollars, and includes expenses during construction. The initial investment cost of condenser wellhead units was taken as 0.7 M$ per MW. The cost of backpressure wellhead units was taken as 0.5 M$ per MW. We used an annual cost of 0.03 M$/year per MW for central plants, 0.06 M$/year per MW for condenser wellhead units, and 0.03 M$/year per MW for backpressure wellhead units. The wellhead units were assumed 5 MW in capacity. The investment cost values used in the development model can be thought of as total cost at start-up.

Steamfield costs include production wells, separators, pipelines, and injection wells; that is, the total cost of delivering steam to a power plant. We lumped these costs into one value and assigned them to a production well. In other words, we assumed that total steamfield costs are proportional to the number of production wells. We selected 2.2 M$ per production well as a representative value. The annual steamfield expenses we estimated 0.3 M$/year per production well. Note that the cost of injection wells, for example, is included in this cost value; we are simply using the production wells as our yardstick. Like the power plant costs, the steamfield costs ought to be thought of as the total cost at start-up.

A project life of 25 years and a discount rate of 10 percent were selected for our study. Costs were discounted to find their net present value at the start of the project.

For a project involving a central plant, the total development cost was arrived at as follows. The initial plant investment cost, plus the sum of the discounted annual plant cost, were added to the the initial steamfield investment cost, plus the discounted annual steamfield costs. In addition, as the deliverability of each well declines with time, more wells need to be drilled to maintain steam production. The cost of the additional wells was discounted to present value along with their annual steamfield costs. For a project involving a wellhead unit, the plants and wells were installed at the same time in pairs. Wells and wellhead plants added after the first year of the project, were discounted to the first year; that is, their investment and annual costs.

The steamfield was assumed to operate every day of the year; at 100 percent capacity. The power plant was assumed to be operated at 80 percent capacity. Therefore, the drawdown in reservoir pressure was calculated assuming the wells were on-line all the time; the cost of electricity was calculated assuming the power plant was on-line 80 percent of the time.

Results and Discussion

The general form of our results is shown in Figure 6. The total cost of project development in million dollars, based on net present value at start-up, is plotted against generation level or installed electric power in megawatts. Consider the nature of this curve. Point A is a 50 MW power project, and point B a 150 MW project. The net present value development cost of the 50 MW project is 100 M$, while the 150 MW project costs almost 450 M$ (447 M$), which give 2000 $/kW and about 3000 $/kW as specific costs, respectively. Figure 6 happens to be based on Ahuachapan match parameters and 5 MW wellhead plants with condensers. The slope of the curve in Figure 6 gives the energy cost from different size developments. For example, at point A the gradient corresponds to a levalized energy cost of 31 mills/kWh, at point B it is 83 mills/kWh, and at point C (90 MW plant) it is 47 mills/kWh. We distinguish between the average and marginal cost. The average cost of energy is found from the slope of a line connecting some point on the curve with the origin. The marginal cost is found from the slope of the tangent to some point on the curve. At point A both the average and marginal costs are the same. At point B, however, the average cost is 47 mills/kWh, but the marginal cost 83 mills/kWh.

Why does the marginal cost of energy increase with generation level? The main reason, we think, is that the flowrate of the production wells decreases more rapidly at high generation

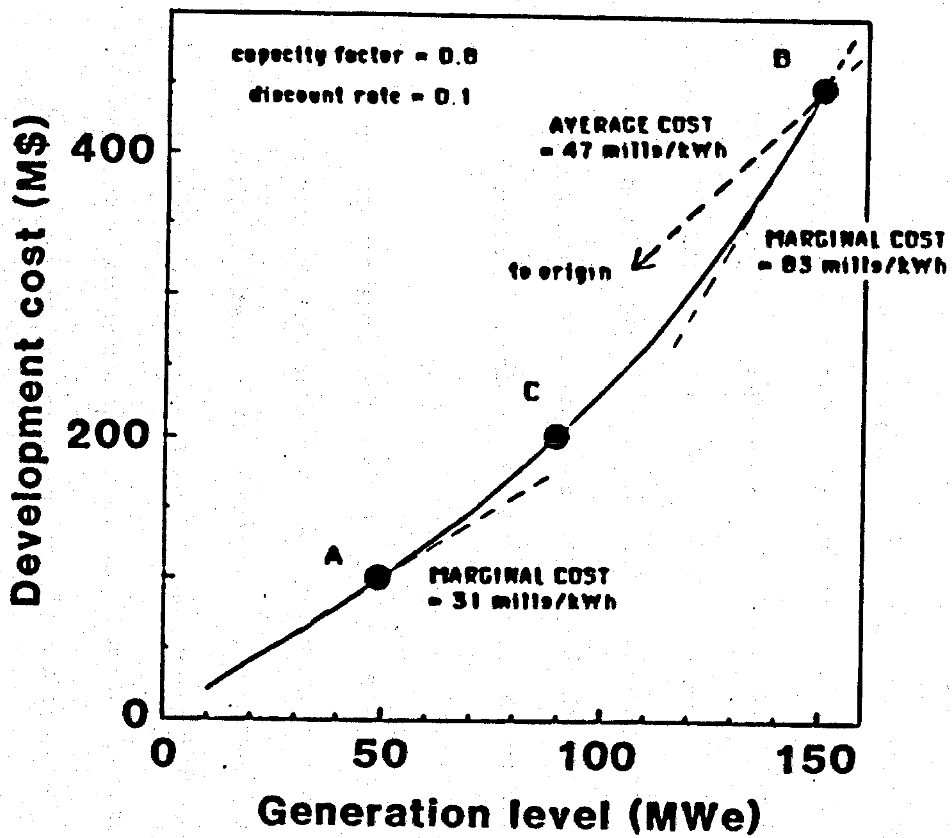

Figure 6. General form of results from development model.

levels than low, but also because we assumed no economy of scale in power plant costs. To illustrate this point: 11 wells are required for the 50 MW project in Figure 6, yet 78 wells are required for the 150 MW project. Therefore, while the generation level tripled, the required number of wells (over the life of the project) increased about seven times. Neither did we lower the cost associated with production wells with time; that is, we assumed the same ratio of injection to production wells at start-up and later. We are forced to conclude that geothermal power developments shown dis-economy of scale when steamfield costs and power plant costs are coupled.

The Geothermal Development Model can be used to study any number of reservoir/wellbore deliverability and power project scenarios. We used the reservoir and economic parameters already discussed, to study the effect of different reservoirs, different power plant choices, and different wellfield operations. In the last of these, we contrasted the effect of constant wellhead pressure production, against constant flowrate production (choked wells). We found that lower development costs were achieved in the constant wellhead pressure case. In our study of different power plant choices, we found the backpressure option was in all cases much more expensive than the condenser option; the reason being the large difference in their conversion efficiency from thermal to electric power.

Figure 7 shows the effect of different types of power plants; that of wellhead units with condensers (same as Figure 6), and a central power station (with condensers). We used the reservoir match parameters for Ahuachapan. At low generation levels the wellhead option costs less, but at high generation level it costs more. This results comes about due to the constraint of having each wellhead unit hooked up to just one well. At high generation levels the flowrate of the wells declines much more than at low generation levels. Each of the wellhead units is generating below what is is capable of generating, resulting in over-installed capacity. In the central plant scenario, on the other hand, the installed capacity is always the same, because make-up wells can be connected to the plant as required. We did the same calculation using match parameters from the Wairakei reservoir. Unlike that shown in Figure 7, the cen-

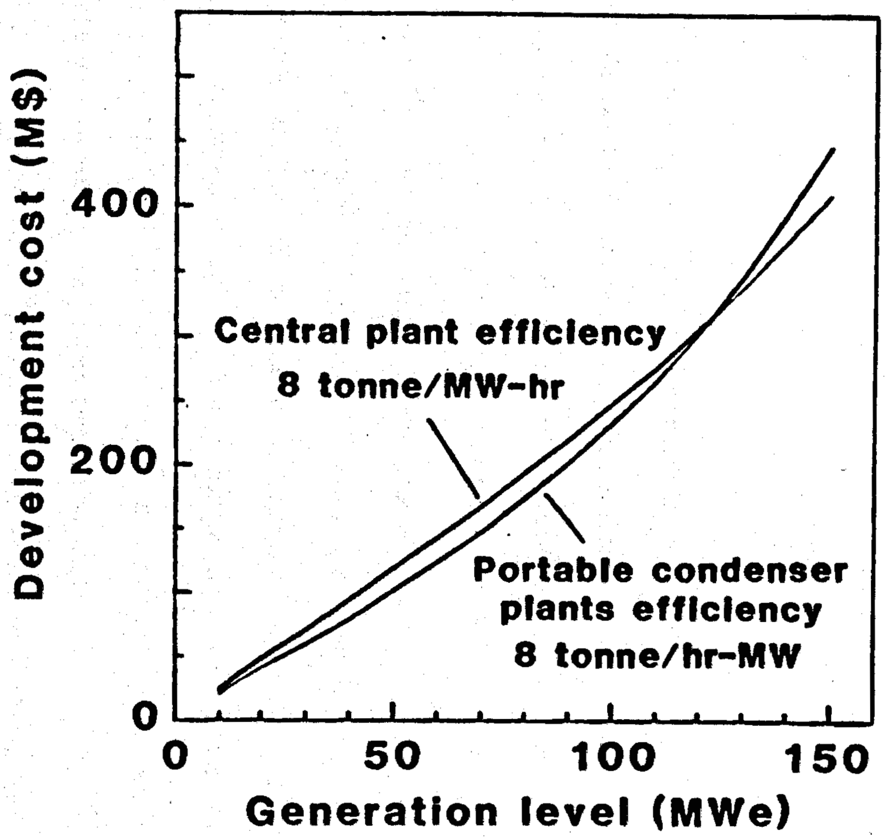

Figure 7. Effect of plant choice on development cost for Ahuachapan match parameters.

tral power plant option costs more at all generation levels, because the reservoir/wellbore deliverability does not decline as much as at Ahuachpan.

The scenario of different size reservoirs for the same type of power plant project, is shown in Figure 8. Using the deliverability of Ahuachapan and Wairakei, we calculated the development cost for wellhead units with condensers. The message of Figure 8 is that there is a great cost advantage in having a large reservoir over that of having a medium or small reservoir. This advantage becomes more pronounced with increasing generation level. At 150 MW the Ahuachapan option has a marginal energy cost of 83 mills/kWh, while the Wairakei option has a marginal cost of 40 mills/kWh.

Conclusions

- The production histories of the liquid-dominated Ahuachapan, Svartsengi, and Wairakei reservoirs, were successfully matched using the radial form of Hurst's simplified water influx method. In the case of Wairakei, for example, six years of production data were sufficient to match the full twenty-five years of history.
- The deliverability of reservoir/wellbore systems consists of reservoir performance, inflow performance, and wellbore performance. Methods and data are available to model the deliverability of liquid-dominated geothermal reservoirs. The methods selected here were intentionally kept simple, so there is ample scope for improvements.
- The Geothermal Development Model can be used to study the effect of reservoir/wellbore deliverability and different power plant schemes on the economics of geothermal electric power. With model refinements, it ought to be possible to optimize geothermal field developments.
- The cost of geothermal electric power and energy increases more rapidly than linearly with the size of development; there exists a dis-economy of scale in geothermal power developments. This effect is especially true for large developments and small and medium sized reservoirs.

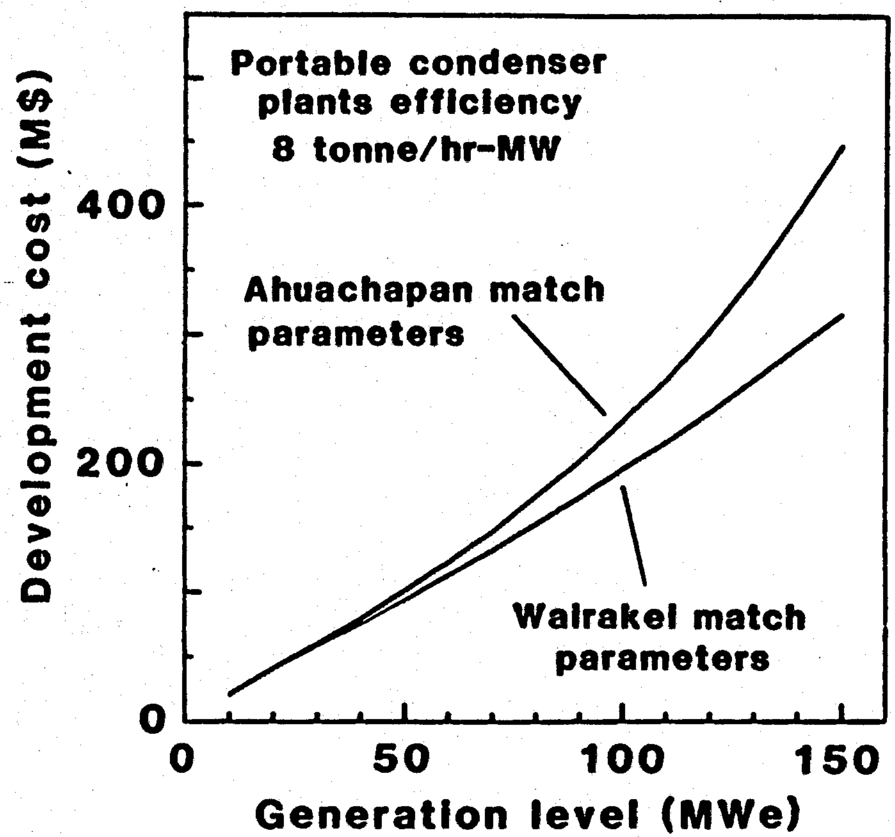

Figure 8. Effect of reservoir/wellbore deliverability on development cost for wellhead condenser plants.

Acknowledgements

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UTAH POWER & LIGHT GEOTHERMAL POWER PROGRAM

Robert D. Davis

U. S. DEPARTMENT OF ENERGY GEOTHERMAL TOPICAL REVIEW MEETING

NOVEMBER 6, 1985

RENO, NEVADA

UTAH POWER & LIGHT GEOTHERMAL POWER PROGRAM

This morning I will address the following topics with reference to Utah Power & Light Company's Geothermal Power Program:

- Early involvement.
- Well drilling experiences, and subsequent acquisition of resource utilization rights.
- Initial reservoir and equipment testing.
- Commercial power plant development.
- Problems encountered during construction and subsequent start-up and operation.
- Present operating status, associated activities and programs.
- Future plans for geothermal power development.

Since the 1960's, Utah Power & Light Company (UP&L) has been exploring geothermal energy as a possible heat source for electric generation.

In 1971, UP&L began funding surveys to determine the geothermal potential within the state. In the mid 1970's, UP&L co-funded a drilling program in northern Utah northwest of Brigham City, and participated in drilling programs in southern Utah west of Cedar City. The temperature of the resource found at these two locations was determined to be inadequate for commercial production of electrical power. In 1974, Phillips Petroleum Company obtained a lease at Roosevelt Hot Springs, approximately 12 miles northeast of Milford, Utah, and discovered a hydrothermal reservoir which has the potential of supporting 200 to 400 MW of electric generation for as long as 35 years. Phillips and UP&L signed a contract in 1980 in which Phillips, as the resource manager, agreed to drill, explore, and provide field operation for the geothermal resource and UP&L agreed to provide a generating plant and steam and brine transportation facilities. Phillips' operating responsibilities are, for the most part, confined to the limits of the production and injection well pad areas.

A cooperative agreement was reached between UP&L, Phillips, and Transamerica Delaval, Inc. (TDI) with participation from Electric Power Research Institute (EPRI) to construct a facility and perform testing on the Roosevelt Geothermal Reservoir. Subsequently a wellhead electric generating system incorporating a rotary separator turbine developed by Biphase Energy Systems and manufactured by TDI was designed and tested.

The skid-mounted RST module arrived by truck at the job site on September 16, 1981. It was synchronized and went on UP&L's grid 57 days later on November 11, 1981. Testing at the facility continued on an intermittent basis until mid-summer of 1984, yielding a great deal of pertinent information concerning the equipment and reservoir characteristics.

Minor modifications were made to the RST during the testing period which invluded a field modification to successfully demonstrate the machines capacity to increase flow from 500,000 to 1,000,000 pounds per hour. During 4,000 hours of operation, there was only minor scaling of the internals of the equipment and few problems of significance were encountered. The rotary separator turbine module operated quite satisfactorily.

Problems encountered during construction and subsequent operation of the wellhead unit involved such items as:

- Tripping the unit due to shorting of the substation when steam from the discharge pond drifted through the equipment.

- Drifting of brine-laden steam over wellhead area equipment, and the general area up to one-quarter mile away, depositing a fine film which was extremely difficult to remove.

- Communication with the outside world, utilizing battery-operated radio telephones which often malfunctioned.

- Ten miles of unimproved dirt and gravel road to the nearest paved highway.

On May 15, 1984, Utah Power & Light Company was presented the Governor's Award for "Excellence in Energy Innovation" at the 1984 Energy Conference held in Salt Lake City, Utah in recognition of the rotary separator turbine wellhead geothermal development program. Subsequently on October 1, 1984, the U.S. Department of Energy, presented Utah Power & Light Company a "Special Award for Energy Innovation" in recognition of a significant contribution to our nation's energy efficiency, at the National Awards Program for Energy Innovation held in Washington D.C. This award was presented in recognition of our sponsorship of the Wellhead Geothermal Development Project.

UP&L's obligation under the 1980 contractual agreement with Phillips was to construct a 20 MW geothermal electric generating power plant. Site preparation for the plant was commenced on March 17, 1982. The plant design incorporated the use of a single flash multiple stage General Electric turbine and generator, an Ecolaire direct contact condenser positioned beneath the turbine, and a four cell B.A.C. Pritchard cross-flow cooling tower. The plant was declared operational on July 31, 1984.

Construction was complicated by the remoteness of the site; contention with heavy winds, ice, and snow during the winter, trucking in fresh water until a three mile pipe delivery system was completed, faulty end bevels on over land piping, and a strike in the manufacturing facility supplying the plant siding. Late delivery of a portion of the manual valves, pipe hangers and electrical equipment, and problems with power cable identification and routing, created further delays.

Subsequent to start-up, operation of the Blundell Plant has been continually hampered by critical problems with vertical multiple stage brine transfer and injection pumps and motors, and pump mechanical seals. This is still an ongoing problem.

The vertical multiple stage brine transfer and injection pumps have had serious alignment and vibration problems which continue to persist in spite of the concentrated effort of the manufacturers. The pumps have had problems such as:

- Shearing of the 2-inch main shaft from torque loading apparently when an unidentified object became lodged in one of the impellers.
- Pump shaft settling until the impeller assemblies contacted, and ground into, the bowl rings causing extensive damage.
- Factory clearance setting for impellers and bowls were inadequate for geothermal operation.
- Bearings freezing to pump shafts.
- Pump shaft wear and grooving in the bearing and seal contact areas.
- Destruction of upper head bearing for no apparent reason.
- Eccentric shaft rotation.
- Drive motor to pump coupling failure.

We have been plagued with brine pump alignment and vibration problems from the beginning of our operation. One train of thought favored by UP&L is that the vibration problems are associated with differential clearances between the pump shafts and the bearings, an average clearance of twelve thousandths of an inch, and the pump shafts and the mechanical seals, with an average clearance of seven thousandths of an inch. The seals failed primarily due to the shaft movement being controlled by the bearings which have greater clearances.

The bolt holes in the pump heads were enlarged to permit greater flexibility for alignment with the motors. Two-piece shafts were removed and replaced with single shafts as a measure for reducing vibration. Also the bearing contact areas on the shafts were hard faced. It is now very apparent that our vertical cannistor brine transfer and injection pumps are not suitable for high temperature and pressure brine service. Our effort is now being directed toward the in service testing of a 75 horse power split case horizontal pump, which we anticipate will be installed in parallel with one of our brine transfer pumps by mid November of 1985.

With reference to our brine pump mechanical seals, we have had on going problems with seal face erosion, scarring, chipping, and heat checking with associated brine and cooling fluid leakage. The seal assembly springs in the single seals repeatedly froze due to chemical build-up from brine water deposits. We have replaced all of our single seals with double seals which do not have the troublesome external spring assemblies. It soon became apparent that the double seal had coolant circulating problems. The seal housing was redesigned to improve the flow of coolant to the inboard seal. The seal face materials were changed from the original carbon-to-carbon to a combination of carbon-to-silicon carbide faces then to the combination of silicon carbide-to-tungsten carbide. The latter combination has been the most successful for controlling heat checking and has given the best service to date.

We have progressed from the original pump seal cooling or buffer systems utilizing brine water coolant circulated by pump rings with fan draft heat exchangers to stainless steel seal cooling systems utilizing turbine oil as a coolant with external motor driven pressurizer circulators and fan draft heat exchangers. The latter system has essentially overcome the circulating coolant temperature problem, and seal face "cooking" which occurred when the circulation of the cooling fluid was dependent upon pumping rings which ceased to operate when the pump shafts stop rotating.

During plant start-up, the main steam valve froze. The valve seat and the disk were manufactured from different types of material and differential expansion occurred. A replacement disk was manufactured from materials having equivalent expansion coefficients and installed in the valve, correcting the problem.

The gross output of the turbine-generator commenced in the range of 23 MW. It soon became apparent that there were serious problems with the system somewhere between the main steam control valve and the condenser. The equipment's capability for producing power steadily degraded over the first eight weeks of operation until gross production was down to about 17 MW. Borascope inspection of the turbine revealed scaling was taking place in the first and second stages. The turbine was opened and inspected. Heavy scaling, mostly silica, was found on the first stage diaphram and blades of the turbine. Indications are that chemical carryover from the primary separators, transported by the steam through the delivery piping, is precipitated in the turbine. In an effort to understand the problem and identify appropriate corrective action, a test program was undertaken. One product of this program was data which indicated that the steam entering the turbine was well within steam purity limits previously thought to be acceptable, yet the turbine still experienced serious scaling.

The gross output of the plant commenced at about 23.5 MW, following the regular monthly blade cleaning operation and deteriated to about 19.5 MW before shutdown. This cycle continued until the middle of June 1985. At this time, in an attempt to reduce the mineral carryover into the turbine, two additional steam pots or traps were added to the main steam line. For the next eight weeks the plant production held more or less steady at a gross output of 21 MW, twice as long as the previous runs with essentially no degradation of production. During the maintenance period in August and September twenty three additional steam traps were added to the steam delivery system, and seventeen existing traps were modified, making a total of forty two traps on the overall steam piping system.

Since start-up, the latter part of September, the plant has only been able to operate at about half load mainly due to production well and brine transfer pump problems. Inspection of the turbine on October 9, 1985 revealed that only a very small amount of scale had been deposited on the first stage diaphragm. Testing is planned over the next few months to determine the effects of the steam trap installations and other modifications on the 20 MW plant operation and to provide design information for future plants. It is felt, however, that a resolution of the turbine scaling issue has been found with the present modifications.

Because of the scale formation in the 20 MW turbine, it has become evident that a steam purity standard has to be established for the proposed future plant units. UP&L is proceeding with the forming of a program for developing such a standard.

A hook and vane separator has been manufactured and is scheduled for installation mid November 1985 on the 20 MW plant system. The separator is to be installed in line with the steam piping adjacent to a production well in order to conduct tests on the steam production system. The purpose of this piece of equipment is to varify that commercially available separation equipment can be used to provide an acceptable steam product, establish an acceptable method for determining the magnitude of the carryover from the existing primary separators, and establish a point which represents a five percent loss of load over a two year period.

In early 1984, a wellhead plant utilizing dual flash was envisioned as the next geothermal plant unit. However, problems with the 20 MW plant and recent load factors have delayed work on the wellhead concept. At present, UP&L is expecting to bring a wellhead plant on line sometime in the mid 1990's.

Not all of the energy available in the geothermal fluid now being produced from the field for the 20 MW Blundell Plant is being utilized. UP&L has contracted with TDI/Biphase Energy Systems to conduct an engineering evaluation on the Blundell Plant to review the possibility of further energy extraction. This application, termed the 20 MW bottoming cycle, presents some unique challenges which must be resolved before it becomes a credible option for our company. With continued effort in this area, the bottoming cycle could become a reality in the late 1980's.

The single flash technology presently employed by the Blundell Plant extracts only a portion of the energy available in the geo-fluid. In order for geothermal energy to remain competitive in our area in the future, plant cycles which extract a much greater portion of the available energy must be utilized. The dual-flash technology and its competitor, dual-flash with the biphase rotary separator turbine, are significantly more efficient than single-flash. A number of test programs are either underway or soon to be commenced, which are designed to verify the appropriate application of dual flash technology at the resource.

Careful cultivation of the geothermal reservoir will be required in order to fully realize and protect this resource's potential. In order to accomplish this objective, a comprehensive understanding of the nature of the resource and its application to the generation of electricity must be developed. A competent reservoir engineer has been retained in our behalf to support this effort.

The Roosevelt Hot Springs Geothermal Resource has the potential of providing our company the option of supplementing its generation base with small, cost competitive geothermal units as the need arises, and our intention is to utilize the resource to this end.